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BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF)
MOHAVE ELECTRIC COOPERATIVE,)
INC., AN ELECTRIC COOPERATIVE)
NONPROFIT MEMBERSHIP CORPORATION)
FOR A DETERMINATION OF THE)
FAIR VALUE OF ITS PROPERTY FOR)
RATEMAKING PURPOSES, TO FIX A JUST)
AND REASONABLE RETURN THEREON AND)
TO APPROVE RATES DESIGNED TO)
DEVELOP SUCH RETURN)

DOCKET NO. E-01750A-11-0136

DIRECT
TESTIMONY
OF
BENTLEY ERDWURM
CONSULTANT
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

FEBRUARY 1, 2012

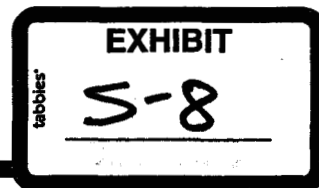


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**EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE
DOCKET NO. E-01750A-11-0136**

This testimony addresses cost allocation and rate design for Mohave Electric Cooperative ("Mohave") with an emphasis on the residential customer charge, the structure of the inclining block residential rate, residential time-of-use rate design, a demand-side management ("DSM") adjustor mechanism and a renewable energy adjustor mechanism. Staff recommends setting the residential customer charge at \$12.00 per month as opposed to Mohave's proposed \$16.50 per month (as compared to a current residential customer charge of \$9.50), increasing the differential among the "inclining" rate blocks in the residential rate, reflecting the inclining block structure in the purchased power component of the rate as well as the distribution component, modifying the peak hours in the residential time-of-use rate, incorporating an inverted block structure into the residential time-of-use rate, and establishing a DSM adjustor mechanism and a renewable energy adjustor mechanism. The Staff recommendations for a lower customer charge, increased inverted block residential rate differentials, and incorporation of the inclining block structure into the residential time-of-use rate help promote the efficient use of energy.

Under Staff's proposal, the median residential customer using 637 kWh per month sees a monthly bill reduction of \$1.44 (2.09% reduction). The bill for the median residential customer is \$77.58 under present rates, and \$75.96 under Staff-proposed rates. Under Mohave's Proposal, the median residential customer using 637 kWh per month sees a monthly bill increase of \$1.50 (1.94% increase). The bill for the median residential customer is \$79.08 under Mohave-proposed rates.

1 **INTRODUCTION**

2 **Q. Please state your name, occupation, and business address.**

3 A. My name is Bentley Erdwurm. I am a Consultant employed by the Arizona Corporation
4 Commission ("Commission") in the Utilities Division ("Staff"). My business address is
5 1200 West Washington Street, Phoenix, Arizona 85007.
6

7 **Q. Briefly describe your responsibilities as a Staff Consultant.**

8 A. I perform cost-of-service, rate design, economic, statistical and regulatory policy analyses
9 and as an expert witness prepare reports and testimonies to present Staff's
10 recommendations to the Commission.
11

12 **Q. Please describe your educational background and professional experience.**

13 A. I earned my Master of Science in Economics from Texas A&M University, and my
14 Bachelor of Arts from the University of Dallas. I have thirty years of utility experience in
15 the areas of cost allocation and rate design, forecasting, valuation and fair market value
16 determination, and utility acquisitions. I have testified before state regulators in Arizona,
17 Texas and Alabama on these issues. I have been employed by the Public Utility
18 Commission of Texas (1982-85), Alabama Gas Corporation (1985-91), Tucson Electric
19 Power Company (1991-99 and 2006-10) and Arizona Public Service Company (1999-
20 2005).
21

22 **SUMMARY OF TESTIMONY AND RECOMMENDATIONS**

23 **Q. What is the scope of your testimony in this case?**

24 A. I will address issues related to cost allocation and rate design for Mohave Electric
25 Cooperative ("Mohave") with an emphasis on the residential customer charge, the
26 structure of the inclining block residential rate, and time-of-use ("TOU") rate design. I

1 will also address the establishment of a demand-side management ("DSM") adjustor
2 mechanism and a renewable energy adjustor mechanism.

3
4 **Q. Have you reviewed Mohave's cost allocation and rate design?**

5 A. Yes. I reviewed the testimony of Mohave's witness, Mr. Michael W Searcy. Mr. Searcy
6 has presented a traditional fully allocated cost of service study ("COSS"), along with
7 Mohave's proposed rate designs.

8
9 **Q. Please summarize your recommendations in this proceeding.**

10 A. My recommendations are:

11 1. Mohave's non-residential rate design proposals should be approved, subject to
12 adjustments for a final revenue requirement determination, an adjustment in the design
13 of the Large Commercial and Industrial Time-of-Use ("TOU") rate (which currently
14 applies to sales amounting to only around 0.1% of revenue) to mitigate a large
15 percentage impact under Mohave's proposal, an adjustment to shift a small portion of
16 the rate increase to larger non-residential customers and away from the residential
17 class, and other minor changes to conform Staff's proof of revenue to the Staff
18 recommended overall revenue levels. Staff has preserved the overall spirit of
19 Mohave's non-residential rate design through maintaining the relative levels of many
20 rate components (i.e., the demand, energy and customer components).

21
22 Recommended percentage revenue increases by class are shown in Exhibits DBE-1
23 and DBE-2 (more detail). Rate design detail and the proof of revenue are shown in
24 Exhibit DBE-3, with residential rate impacts in Exhibit DBE-4.

1 2. Mohave's proposal to increase the residential customer charge to \$16.50 per month
2 should be rejected. The residential customer charge should be set at \$12.00 per month.
3 The lower customer charge will promote the efficient use of scarce energy resources.
4 Staff's recommendation here is consistent with cost-of-service principles. Staff and
5 Mohave have a different view of what should be classified as "customer-related" in a
6 COSS.

7
8 3. Staff proposes a modification in the inverted block structure (the price of incremental
9 usage increases as usage increases) of the residential rate as proposed by Mohave.
10 Under Staff's modification, the differential between rate blocks increase (i.e., usage
11 becomes relatively more expensive in the higher use blocks), which reduces bills to
12 lower-use customers and increases bills to higher-use customers. This modification
13 also enhances the incentive promoting the efficient use of energy resources, and makes
14 a block of energy serving basic needs more affordable. In light of the larger
15 differential, Staff recommends an inverted structure for both the purchased power
16 component and the distribution component of the residential rate because the benefits
17 of promoting efficient energy use apply to both components.

18
19 4. Staff proposes that the number of peak hours in Mohave's residential time-of-use rate
20 be reduced. Typically, shorter peak periods are more effective at controlling
21 coincident peak demand spikes in Arizona's desert climate.

22
23 5. Staff proposes that an inclining block structure also be incorporated into the residential
24 time-of-use rate. This would prevent higher use residential customers from "gaming
25 the system" by switching to time-of-use to avoid the inclining block structure in the
26 regular non-TOU residential rate.

1 **NON-RESIDENTIAL RATE DESIGN**

2 **Q. Please discuss your proposed adjustment to Mohave's Large Commercial and**
3 **Industrial Time-of-Use rate.**

4 A. Mohave has modified the Large Commercial and Industrial TOU rate to include both a
5 demand charge applying only during the peak period (i.e., during the "on-peak" time-of-
6 use hours) and a new "NCP" (non-coincident peak) demand charge that applies over all
7 hours of the day. Currently, the rate only includes the on-peak demand charge, a customer
8 charge and an energy charge. The current on-peak demand charge is \$13.50 per kW-
9 month and the Mohave-proposed on-peak demand charge is \$23.00 per kW-month.
10 Mohave has proposed a new NCP demand charge of \$2.99 per month. The Company's
11 purpose in adding the NCP demand charge is to insure that all customers, even those using
12 power primarily during off-peak periods, contribute to covering some demand-related
13 costs. This helps eliminate what is referred to as a free-rider problem, and Staff agrees
14 that two demand charges are appropriate. Moreover, having both an "on-peak" demand
15 charge and an NCP demand charge is a more cost-based design that recognizes that
16 "upstream" costs (incurred closer to power generation and further from the end-use
17 customer) are more driven by the level of "on-peak demand" (system-wide coincident
18 peaks) and "downstream" costs (incurred further from power generation and closer to the
19 end-use customer) are more driven by NCP demand (localized non-coincident peaks).
20 Mohave appropriately has proposed using its proposed "on-peak" demand charge to
21 recover purchased power costs (upstream) and its NCP demand charge to recover
22 distribution costs (more-downstream). The Staff proposal maintains this structure.

23
24 Mohave's approach would be reasonable for designing a new rate. However, this Large
25 Commercial and Industrial TOU rate is an existing rate, and Mohave's proposal results in
26 a percentage revenue increase of over 40% to customers served thereunder. To address

1 the bill impact issue, Staff proposes an on-peak demand charge of \$11.11 and an NCP
2 demand charge of \$3.08 per kW-month (to match many other Staff-proposed NCP
3 demand charges (distribution portion) in the commercial-industrial rates), and plus
4 customer charge and energy charge components as shown in Exhibit DBE-3. Staff's
5 redesign of the rate results in a revenue increase of approximately 26%, still substantial
6 but necessary to provide proper incentives.

7
8 Subscription to the current rate is very low. During the test year, the rate accounted for
9 only about 0.1% of system revenue. The substantial impact of Mohave's proposed
10 redesign indicates that current customers may have load profiles inconsistent with time-of-
11 use.

12
13 **PERCENTAGE INCREASE FOR THE RESIDENTIAL CLASS**

14 **Q. You indicated that a small portion of the rate increase has been shifted to non-**
15 **residential customers and away from residential customers.**

16 **A.** The impact is small; however, in the current economic climate, Staff believes that the
17 residential percentage increase should not exceed the system percentage increase, unless
18 compelling cost considerations indicate otherwise. In this case, Mohave has proposed a
19 residential percentage increase of 4.07% and an overall percentage increase of 3.94%.
20 Staff has proposed a residential percentage increase of 3.81% and an overall percentage
21 increase of 3.82%, essentially equal. The differences between Mohave's and Staff's
22 allocation of the revenue increase are minor, and there exists no practical reason that the
23 residential percentage increase cannot be capped at the system increase.

1 **ALLOCATED COST OF SERVICE STUDY**

2 **Q. Please discuss the structure, purpose and some limitations of a fully allocated cost-of-**
3 **service study.**

4 **A.** Cost allocation involves the assignment of joint costs of providing utility service to
5 various classes or groups of customers. There is no single correct way to allocate these
6 joint costs. In fact, there are multiple "reasonable" ways to use COSSs to assign revenues
7 among customer classes, because there are multiple "reasonable" COSSs.

8
9 Because the quest for cost-based rates can lead to a range of scenarios for revenue
10 assignments among customer classes, other non-cost-of-service based criteria can (and
11 should) be used to winnow out less beneficial options and to determine the best revenue
12 allocation and rate design for a specific utility and its customers at a specific time. Other
13 criteria (e.g., avoidance of adverse customer impact, potential loss of load from self
14 generation or plant closure, potential job losses, economic development, or the promotion
15 of renewable generation), in addition to cost of service considerations, may be considered
16 to determine revenue allocation and rate design. The attainment of higher priority non-
17 cost-of-service goals often trumps the strict application of any specific allocated cost-of-
18 service study. A COSS serves as a guideline, not a straightjacket, in setting rates.

19
20 Utilities typically are required to file COSSs in an application to change rates. Such a
21 study provides a cost basis and guideline for rate design. As mentioned, other studies may
22 reasonably allocate costs differently – and could be used to construct quite different rate
23 designs – however; the utility's proposed COSS study, even if conflicting with the studies
24 of other parties, allows a rate proposal to be characterized (at least by the utility) as cost-
25 based. The purpose of a COSS is to assign each cost component to the respective classes
26 in order to approximate (based on the COSS assumptions used) a total cost to serve each

1 class. A cost component may be: (1) an individual rate base or expense account; (2) a
2 portion of a single account, or (3) some composite of accounts.

3
4 **Q. Please briefly describe the steps in a fully allocated cost-of-service study.**

5 A. There are three basic steps involved in developing a COSS: functionalization,
6 classification, and allocation. Functionalization involves grouping cost components by
7 purpose or function. Examples of functional categories for an electric utility include
8 transmission, distribution-primary, metering, and meter-reading. The next step,
9 classification, involves identifying each function as demand-related, energy-related or
10 customer-related. The final step, allocation, involves apportioning each cost component to
11 the classes of service (e.g., residential, commercial and industrial).

12
13 **Q. Please describe how costs are classified for purposes of the COSS.**

14 A. Costs classified as demand are most affected by the level of kW by class. These demand-
15 classified costs are either coincident, meaning that they occur at the same time, or non-
16 coincident, meaning at times that may vary. Coincident demands tend to be more
17 correlated with cost at the production level. In other words, coincident demands address
18 whether there is purchased power and generation capacity for a utility's entire system
19 needs. Consequently, non-coincident demands become more correlated with cost as we
20 move downstream through the distribution system to the end-users.

21
22 Costs classified as energy are most affected by kWh by class. The energy classification
23 can be affected either by time-of-day (e.g., on-peak, shoulder-peak, and off-peak) or non-
24 time-differentiated.

25

1 Finally, costs classified as customer are based on class customer counts - either non-
2 weighted counts or weighted counts. Weighted counts take into account not just the
3 number of customers but the level of costs imposed by the customers. In dealing with
4 billing costs, for example, a residential customer may be defined as one "weighted
5 customer" and an industrial customer that costs twenty times as much to meter would
6 count as twenty "weighted customers". A proper classification helps insure that
7 deviations in sales due to conservation, economic conditions, or weather conditions do not
8 result in significant over-recoveries or under-recoveries.

9
10 **Q. Please describe the allocation step in designing a COSS.**

11 **A.** As I stated above, allocation involves assigning each cost component to the different
12 classes of service, including residential, commercial, industrial and lighting. Each
13 function has a single allocation factor that applies to all cost components in that function.
14 The allocation factor should be based upon an equitable method that harmonizes (to the
15 extent possible) cost causation with the functional cost being considered. The purpose of
16 a COSS is to assign each cost component to the respective classes in order to approximate
17 an appropriate total cost to serve each class. As mentioned, specific cost allocation
18 approaches may be disputed because there is often more than one reasonable way to
19 allocate cost. As a general example, consider the cost to serve certain off-peak lighting
20 customers. If we assign cost responsibility for certain items based on coincident peak
21 demand, lighting customers may have zero use at the time of the system peak. Does that
22 mean that lighting customers should contribute nothing for the use of facilities they only
23 use during off-peak periods? That is, should lighting customers be free riders? There is
24 no single correct way to allocate these joint costs. A simple non-utility cost allocation
25 example involves the allocation of a cab fare between an airport and a hotel. If person
26 "A" was willing to pay \$15 for a cab ride alone, how much should "A" pay of the \$15 if

1 person "B" joins him? Should "A" and "B" each pay half, \$7.50, or should "A" pay the
2 whole \$15 because he had previously been willing to pay \$15 to travel alone over the
3 same route? Again, there is no single correct allocation approach.
4

5 **Q. Does Staff agree with Mohave's COSS methodology as presented in the testimony of**
6 **Mohave witness, Mr. Michael W Searcy?**

7 A. It is not the position of Staff that Mohave's proposed functionalization, classification, and
8 allocation techniques used in its proposed COSS fall outside the bounds of standard
9 industry practice, and for this reason Staff is recommending revenue increases similar to
10 Mohave's proposal, subject to being scaled down to conform with the final revenue
11 requirement determination and shifting a small amount of the increase away from the
12 residential class. However, Mohave's use of the customer classification for distribution
13 items separate from the functions of metering, meter-reading, the service drop, billing and
14 customer service is not acceptable to Staff.
15

16 **CUSTOMER CHARGES – RESIDENTIAL AND SMALL COMMERCIAL**

17 **Q. How does Mohave's classification approach affect its rate design proposals?**

18 A. Mohave's approach inflates its proposed residential customer charge to \$16.50 per month,
19 which is in excess of a more appropriate charge of \$12.00 per month supported by Staff.
20 When the customer classification applies to items other than metering, meter reading, the
21 service drop, billing and customer service - the items most directly tied to establishing and
22 maintaining a customer's connection to the system – the resulting COSS-based customer
23 charge increases and the COSS-based usage (volumetric) charge decreases. This creates a
24 price signal that runs counter to encouraging the efficient use of electricity. The "law of
25 demand" says that a lower incremental price of consumption (lower usage charge) could
26 promote electric usage in excess of efficient levels (i.e., lower price leads to higher

1 quantity demanded). Energy charges that are set too low fail to recognize costs associated
2 with excessive energy consumption.

3
4 The current customer charge is only \$9.50 per month. Mohave notes that the current
5 charge was established over twenty years ago, and that the annualized increase is
6 reasonable. However, Staff contends that a customer charge is excessive if it collects
7 substantially more than the amount necessary to establish and maintain a customer's
8 connection to the system. Based on Mohave's response to a data request (Staff's sixth
9 Data Request, Q. 1), a monthly charge of \$11.71 covers the metering, meter reading, the
10 service drop, billing and customer service. Moreover, an increase in the customer charge
11 from \$9.50 even to the Staff-proposed \$12.00 represents a substantial impact to some
12 customers. An increase from \$9.50 to \$16.50 (with no phase-in period) creates an
13 unacceptable impact. Staff's recommendation to scale back Mohave-proposed customer
14 charges applies also to the Residential Time-of Use rate. Staff recommends that the
15 Residential Time-of-Use customer charge be kept at the current level of \$15.00 per month,
16 and not increased to \$21.50 as proposed by Mohave. Likewise, Staff-proposed customer
17 charges for Residential rates with lower subscription are set at the levels shown in Exhibit
18 DBE-3. Because Small Commercial Energy and Small Commercial -Net Metering
19 customer charges are based on residential charges, Staff proposes reducing the Small
20 Commercial Energy customer charge from Mohave-proposed \$21.50 per month to a Staff-
21 proposed charge of \$17.00. The Staff-Proposed Small Commercial-Net Metering
22 customer charge is \$18.50 per month, compared to the Mohave-proposed \$30.00.

RESIDENTIAL INCLINING BLOCK RATE

Q. Please discuss your recommendation for structuring of the residential inclining block rate and compare your recommendation to Mohave's proposal.

A. Under Staff's recommendation, the differentials between rate blocks is larger (i.e., usage becomes relatively more expensive in the higher use blocks), which lowers bills to lower-use customers and increases bills to higher-use customers. Staff is proposing a 1.5 cent differential between the first and second blocks and a 1.5 cent differential between the second and third blocks – for a total of a 3.0 cent differential between the first and third blocks. Mohave is proposing a 1.0 cent differential between the first and second blocks and a 1.0 cent differential between the second and third blocks – for a total of a 2.0 cent differential between the first and third blocks. Staff's proposed modification enhances the incentive promoting the efficient use of scarce energy resources, and makes a block of energy serving basic needs more affordable.

Staff recognizes that larger differentials place more "distribution wires" revenue at risk. To the extent that customers respond to the inclining block rate, use per customer will fall. Under an inclining block structure, a utility will lose the highest margin load as second and/or third block (higher usage blocks) usage declines. Other things constant, higher differentials can aggravate margin loss. For this reason, Staff recommends an inverted block structure for both the purchased power component and the distribution wires component of the residential rate. This is appropriate because the benefits of promoting efficient energy use apply to both components. Under Staff's proposal, 1.35 cents of the 1.5 cent differential (90% of the differential) is applied to the purchased power component, and 0.15 cents (10% of the differential) is applied to the distribution wires component. The Staff proposal is a win/win for the promotion of efficient energy use, and for Mohave's margin (wires revenue) stability. Mohave placed the entire differential

1 between blocks (1 cent escalation per block; 2 cents total differential between 1st and 3rd
2 blocks) in the distribution wires component, thereby subjecting the utility to more
3 potential margin loss than would exist under Staff's proposal.
4

5 **RESIDENTIAL TIME-OF-USE PEAK HOURS**

6 **Q. Please discuss your recommendation for the peak hour definition for residential**
7 **time-of-use rates and compare your recommendation to Mohave's proposal.**

8 A. Mohave has proposed an Option 1, under which peak periods apply only to weekdays, and
9 Option 2, under which peak periods apply for both weekdays and weekends. Currently,
10 Mohave has a Residential TOU rate offering with weekends all off-peak and a nine-hour
11 daily on-peak window. Subscription to the current rate is low.
12

13 Mohave's decision to offer both options is a positive move that could expand the appeal of
14 the TOU options. Under Mohave's proposed Option 1 (peak on weekdays only), Mohave
15 has designated the summer (April 16-October 15) peak period as 12:00 p.m. (noon) to
16 9:00 p.m. (9 hours). Under proposed Option 2, (peak applies weekdays and weekends),
17 Mohave has designated the summer peak period as 2:00 p.m. to 8:30 p.m. (6.5 hours).
18 Staff recommends that the summer peak period for both options end at 7:30 p.m., and that
19 it begin no earlier than 1:00 p.m. for either option. Either 1:00 p.m. or 2:00 p.m. is an
20 appropriate summer peak start time under either option. Under Staff's recommendation,
21 the summer peak period will be 6.5 hours for a 1:00 p.m. peak start time, and 5.5 hours for
22 a 2:00 p.m. peak start time. Staff realizes that weekday and weekend load profiles differ.
23 If Mohave has some specific reasons for using different peak hours for Options 1 and 2,
24 Mohave should provide testimony explaining those reasons. However, Staff's review of
25 load profiles does not indicate that different peak hours are required.
26

1 Shortening the summer peak period:

- 2 1. eliminates hours where the probability of a system peak (based on load data
3 provided in response to Staff's Sixth Data Request, question 3) is significantly
4 smaller than "super-peak" hours in which the peak occurs most often (2:00
5 p.m. to 6:00 p.m.),
- 6 2. avoids overly long peak periods that can result in customers needlessly
7 sacrificing comfort when power is not in critically short supply,
- 8 3. avoids potential peaks that can result when customers who have shown
9 restraint for six or more hours reason that an hour or two of higher peak usage
10 has been earned by the sacrifice in the early hours, and
- 11 4. makes the rate more attractive and could increase subscription.

12
13 Time-of-use programs should not require needless sacrifice brought on by overly long
14 peak periods. Arizona's extreme desert climate is easier to bear if summer peak periods
15 are kept short. Staff recommends acceptance of Mohave's proposed winter peak hours
16 (Option 1: 6:00 a.m. to 10:00 a.m. and 5:30 pm. to 10:00 p.m.; and Option 2: 6:30 a.m. to
17 9:30 a.m. and 5:30 pm. to 9:00 p.m.).

18
19 Staff notes that Mohave has attempted to use the same prices while adjusting the hours to
20 account for differences in the number of peak hours in Options 1 and 2. Another approach
21 would be to use the same peak hours for both options (except for weekday and weekend
22 differences) and change the prices.

RESIDENTIAL TIME-OF-USE INCLINING BLOCK RATE

Q. Please discuss your recommendation to incorporate an inclining block provision into Mohave's residential time-of-use rates.

A. This would prevent higher use residential customers from "gaming the system" by switching to time-of-use to avoid the inclining block structure in the regular non-TOU residential rate. The inclining block structure could be implemented simply by applying a first block adder to first block kWh (1st 400 kWh), a second block adder to second block kWh (next 600 kWh), and a third block adder to third block kWh (over 1000 kWh). The first block adder will reduce the effective kWh charge in that block (it will be negative). The second block adder will equal the first block adder plus 1.5 cents and the third block adder will equal the second block adder plus 1.5 cents. The goal is to send a price signal that will promote the efficient use of energy.

DSM ADJUSTOR MECHANISM

Q. Please discuss your recommendation for a DSM adjustor mechanism?

A. Mr. Searcy indicates on page 15, lines 1-7, of his direct testimony that Mohave intended to file a separate request for recovery of DSM expenses through a DSM adjustor, and that DSM related expenses have been removed from adjusted test-year expenses. On June 1, 2011, Mohave filed its proposed 2012-13 demand-side management and energy efficiency ("EE") implementation plan in Docket No. E-01750A-11-0228, pursuant to the Electric Energy Efficiency Standards ("EEE rules"). Mohave included a request for approval of a DSM adjustment tariff within that filing. Staff recommends that a DSM adjustment mechanism be established within this rate case, with the initial adjustor rate to be approved by the Commission in Docket No. E-01750A-11-0228.

1 Staff believes that a DSM adjustor mechanism will provide flexibility to adjust the level of
2 DSM spending as new programs are added/deleted and current programs are adjusted
3 between rate cases, while also providing timely recovery of DSM costs. Separating DSM
4 costs from other costs included in base rates promotes transparency and allows customers
5 to see the costs of the DSM programs. Also, separating DSM costs from other costs
6 provides Mohave the incentive to initiate programs at any time; Mohave need not wait for
7 a rate case. Finally, separating DSM costs from other costs protects customers from
8 paying DSM costs not actually incurred by Mohave.

9
10 **Q. What costs should be recoverable through the DSM adjustor mechanism?**

11 A. Recoverable costs should include DSM costs and related costs prudently incurred by
12 Mohave for Commission-approved DSM programs and activities. Allowable costs
13 include costs for rebates and other incentives, including rebate processing; training and
14 technical assistance, customer education, program planning and administration, program
15 implementation, marketing and communications, monitoring and evaluation, and baseline
16 studies.

17
18 **Q. How would the DSM adjustor mechanism rate be applied to customer bills?**

19 A. The DSM adjustor mechanism rate would be assessed on a per-kWh basis and would be
20 shown as a separate line item on the customer bills. The bill would show the unit charge
21 and the number of kWh to which the charge applies. In the event that kWh is not metered
22 (e.g., lighting), imputed kWh would be used for the adjustment, and the bill presentation
23 may vary.

1 **Q. When would the DSM adjustor be reset?**

2 A. The DSM adjustor mechanism rate would be reset after Commission approval of each
3 Mohave DSM and EE implementation plan. The EE rules require an implementation plan
4 to be filed by June 1 in every odd year, although the utility has the option to file annually.
5 In years when the utility does not file an implementation plan, Mohave could file an
6 application for a change in the adjustor rate.

7

8 **RENEWABLE ENERGY ADJUSTOR MECHANISM**

9 **Q. Please discuss your recommendation for a renewable energy adjustor mechanism.**

10 A. Mohave currently has a Renewable Energy Standard Tariff. Staff recommends that the
11 tariff become an adjustment mechanism. The adjustor rates should be the same as
12 contained in the tariff, including caps. The rates and caps would be reset only after
13 Commission approval of a renewable energy implementation plan or a separate
14 application to revise the rates or caps.

15

16 **Q. Does this conclude your direct testimony?**

17 A. Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES

	Cust	kWh		Adjusted 2010	Mohave Proposed 2010	Change		Staff Proposed 2010	Change	
		Total	Avg Mn			\$	%		\$	%
Residential	34,875	364,970,959	872	42,986,712	44,735,329	1,748,617	4.07%	44,625,239	1,638,527	3.81%
Irrigation Time of Use	12	1,730,345	12,016	166,306	168,026	1,720	1.03%	167,368	1,062	0.64%
Irrigation Pumping	11	2,572,007	19,485	302,194	309,962	7,768	2.57%	308,398	6,204	2.05%
Subtotal Irrigation	23	4,302,352	15,588	468,500	477,988	9,488	2.03%	475,766	7,266	1.55%
Small Comm Energy	3,201	42,164,591	1,098	4,900,351	5,177,391	277,040	5.65%	5,182,804	282,453	5.76%
Small Comm Demand	529	70,626,268	11,126	7,389,210	7,729,118	339,908	4.60%	7,703,729	314,519	4.26%
Small Comm TOU	8	1,020,044	10,625	96,177	100,936	4,759	4.95%	101,248	5,071	5.27%
Subtotal Small Comm	3,738	113,810,903	2,537	12,385,738	13,007,445	621,707	5.02%	12,987,781	602,043	4.86%
Large Comm & Industrial	118	170,994,538	4,495,062	15,775,430	16,108,634	333,204	2.11%	16,103,338	327,908	2.08%
LC&I TOU	3	564,880	15,691	48,035	67,443	19,408	40.40%	60,365	12,330	25.67%
Lighting Devices	* 1,151	1,100,103	80	98,025	103,184	5,159	5.26%	103,596	5,571	5.68%
Resale	* 1	46,862,961	3,905,247	3,698,667	3,698,667	0	0.00%	3,698,667	0	0.00%
Total Energy Sales	* 38,757	702,606,696	1,511	75,461,107	78,198,690	2,737,583	3.63%	78,054,752	2,593,645	3.44%
Other Revenue				606,899	863,547	256,647	42.29%	919,367	312,468	51.49%
Total Revenue				76,068,007	79,062,237	2,994,230	3.94%	78,974,119	2,906,112	3.82%

* Total Customers excludes Lighting Devices and Resale

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES (DETAIL)

	Cust	kWh		Adjusted 2010	Cents per kWh	Mohave		Cents per kWh	Change under Mohave Proposal		Staff Proposed 2010	Cents per kWh	Change under Staff Proposal	
		Total	Avg Mn			Proposed 2010			\$	%			\$	%
Residential	34,775	364,111,753	873	\$ 42,878,813	11.8	\$ 44,621,441	12.3	\$ 1,742,628	4.06%		\$ 44,512,327	12.2	\$ 1,633,515	3.81%
Residential - Seasonal	1	549	46	\$ 164	29.9	\$ 235	42.8	\$ 71	43.29%		186	33.9	\$ 22	13.58%
Residential - Net Metering	72	640,060	741	\$ 81,352	12.7	\$ 86,113	13.5	\$ 4,761	5.85%		\$ 85,736	13.4	\$ 4,384	5.39%
Res - Gov	27	218,597	675	\$ 26,383	12.1	\$ 27,540	12.6	\$ 1,157	4.38%		\$ 26,989	12.3	\$ 606	2.30%
Residential	34,875	364,970,959	872	\$ 42,986,712	11.8	\$ 44,735,329	12.3	\$ 1,748,617	4.07%		\$ 44,625,239	12.2	\$ 1,638,527	3.81%
Irrigation Time of Use	12	1,730,345	12,016	\$ 166,306	9.6	\$ 168,026	9.7	\$ 1,720	1.03%		\$ 167,368	9.7	\$ 1,062	0.64%
Irrigation Pumping	11	2,572,007	19,485	\$ 302,194	11.7	\$ 309,962	12.1	\$ 7,768	2.57%		\$ 308,398	12.0	\$ 6,204	2.05%
Subtotal Irrigation	23	4,302,352	15,588	\$ 468,500	10.9	\$ 477,988	11.1	\$ 9,488	2.03%		\$ 475,766	11.1	\$ 7,266	1.55%
Small Commercial Energy	2,930	38,541,431	1,096	\$ 4,479,803	11.6	\$ 4,733,078	12.3	\$ 253,275	5.65%		\$ 4,738,140	12.3	\$ 258,337	5.77%
SC Energy Gov	267	3,559,150	1,111	\$ 413,221	11.6	\$ 436,237	12.3	\$ 23,016	5.57%		\$ 436,881	12.3	\$ 23,660	5.73%
SC Energy - Net Metering	4	64,010	1,334	\$ 7,327	11.4	\$ 8,076	12.6	\$ 749	10.22%		\$ 7,783	12.2	\$ 456	6.22%
Small Comm Energy	3,201	42,164,591	1,098	\$ 4,900,351	11.6	\$ 5,177,391	12.3	\$ 277,040	5.65%		\$ 5,182,804	12.3	\$ 282,453	5.76%
Small Commercial Demand	463	63,019,478	11,343	\$ 6,561,332	10.4	\$ 6,854,527	10.9	\$ 293,195	4.47%		\$ 6,831,610	10.8	\$ 270,277	4.12%
SC Demand Gov	65	7,582,510	9,721	\$ 825,265	10.9	\$ 871,832	11.5	\$ 46,567	5.64%		\$ 869,367	11.5	\$ 44,103	5.34%
SC Demand - Net Metering	1	24,280	2,613	\$ 2,613	10.8	\$ 2,759	11.4	\$ 146	5.58%		\$ 2,752	11.3	\$ 139	5.33%
Small Comm Demand	529	70,626,268	11,126	\$ 7,389,210	10.5	\$ 7,729,118	10.9	\$ 339,908	4.60%		\$ 7,703,729	10.9	\$ 314,519	4.26%
Small Comm TOU	8	1,020,044	10,625	\$ 96,177	9.4	\$ 100,936	9.9	\$ 4,759	4.95%		\$ 101,248	9.9	\$ 5,071	5.27%
Subtotal Small Comm	3,738	113,810,903	2,537	\$ 12,385,738	10.9	\$ 13,007,445	11.4	\$ 621,707	5.02%		\$ 12,987,781	11.4	\$ 602,043	4.86%
Large Power Sec	82	76,311,058	77,552	\$ 7,200,844	9.4	\$ 7,578,027	9.9	\$ 377,183	5.24%		\$ 7,578,395	9.9	\$ 377,550	5.24%
LP Gov	30	17,180,160	47,723	\$ 1,842,672	10.7	\$ 1,963,366	11.4	\$ 120,694	6.55%		\$ 1,967,193	11.5	\$ 124,521	6.76%
Large Power Primary	3	8,497,320	236,037	\$ 758,514	8.9	\$ 781,262	9.2	\$ 22,748	3.00%		\$ 780,495	9.2	\$ 21,981	2.90%
LP Subtransmission	1	30,204,000	2,517,000	\$ 2,625,974	8.7	\$ 2,493,869	8.3	\$ (132,105)	-5.03%		\$ 2,493,468	8.3	\$ (132,506)	-5.05%
LP Substation	2	38,802,000	1,616,750	\$ 3,347,425	8.6	\$ 3,292,110	8.5	\$ (55,315)	-1.65%		\$ 3,283,787	8.5	\$ (63,638)	-1.90%
Large Comm & Industrial	118	170,994,538	4,495,062	\$ 15,775,430	9.2	\$ 16,108,634	9.4	\$ 333,204	2.11%		\$ 16,103,338	9.4	\$ 327,908	2.08%
LC&I TOU	3	564,880	15,691	\$ 48,035	8.5	\$ 67,443	11.9	\$ 19,408	40.40%		\$ 60,365	10.7	\$ 12,330	25.67%
Lighting Devices	1,151	1,100,103	80	\$ 98,025	8.9	\$ 103,184	9.4	\$ 5,159	5.26%		\$ 103,596	9.4	\$ 5,571	5.68%
Resale	1	46,862,961	3,905,247	\$ 3,698,667	7.9	\$ 3,698,667	7.9	\$ -	0.00%		\$ 3,698,667	7.9	\$ -	0.00%
Total Energy Sales	38,757	702,606,696	1,511	\$ 75,461,107	10.7	\$ 78,198,690	11.1	\$ 2,737,583	3.63%		\$ 78,054,752	11.1	\$ 2,593,645	3.44%
Other Revenue				\$ 606,899		\$ 863,547		\$ 256,647	42.29%		\$ 919,367		\$ 312,468	51.49%
Total Revenue				\$ 76,068,007		\$ 79,062,237		\$ 2,994,230	3.94%		\$ 78,974,119		\$ 2,906,112	3.82%

* Total Customers excludes Lighting Devices and Resale

MOHAVE ELECTRIC COOPERATIVE, INC.

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.
DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate		Pur Pwr	Proposed Revenue		Total
		Dist Wires	Total		Dist Wires	Total	
1. RESIDENTIAL SERVICE (Continued)							
Residential - Net Metering							
Service Charge (12 Month Sum)	863	\$	\$ 17.50	-	\$	\$ 15,103	\$ 15,103
Energy Charge per kWh							
First 200 kWh per month	114,805	\$ 0.079958	\$ 0.014865	9,180	\$	\$ 1,707	\$ 10,886
Next 200 kWh per month	97,201	\$ 0.079958	\$ 0.014865	7,772	\$	\$ 1,445	\$ 9,217
Next 200 kWh per month	79,816	\$ 0.093458	\$ 0.016365	7,459	\$	\$ 1,306	\$ 8,766
Next 200 kWh per month	63,706	\$ 0.093458	\$ 0.016365	5,954	\$	\$ 1,043	\$ 6,996
Next 200 kWh per month	49,825	\$ 0.093458	\$ 0.016365	4,657	\$	\$ 815	\$ 5,472
Over 1,000 kWh per month	234,706	\$ 0.106958	\$ 0.017865	25,104	\$	\$ 4,193	\$ 29,297
Base Revenue	640,060			60,125	\$	\$ 25,611	\$ 85,736
PPCA Revenue					\$	\$ -	\$ -
Total Revenue				60,125	\$	\$ 25,611	\$ 85,736
Res - Gov							
Service Charge (12 Month Sum)	318	\$	\$ 12.00	-	\$	\$ 3,816	\$ 3,816
Energy Charge per kWh							
First 200 kWh per month	60,246	\$ 0.079958	\$ 0.014865	4,817	\$	\$ 896	\$ 5,713
Next 200 kWh per month	44,692	\$ 0.079958	\$ 0.014865	3,573	\$	\$ 664	\$ 4,238
Next 200 kWh per month	28,446	\$ 0.093458	\$ 0.016365	2,659	\$	\$ 466	\$ 3,124
Next 200 kWh per month	20,173	\$ 0.093458	\$ 0.016365	1,885	\$	\$ 330	\$ 2,215
Next 200 kWh per month	15,693	\$ 0.093458	\$ 0.016365	1,467	\$	\$ 257	\$ 1,723
Over 1,000 kWh per month	49,347	\$ 0.106958	\$ 0.017865	5,278	\$	\$ 882	\$ 6,160
Base Revenue	218,597			19,679	\$	\$ 7,310	\$ 26,989
PPCA Revenue					\$	\$ -	\$ -
Total Revenue				19,679	\$	\$ 7,310	\$ 26,989
Base Revenue	364,970,959			33,674,179	\$	\$ 10,951,060	\$ 44,625,239
PPCA Revenue				-	\$	\$ -	\$ -
Total Revenue				33,674,179	\$	\$ 10,951,060	\$ 44,625,239

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.
DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
2. IRRIGATION SERVICE							
<u>Irrigation Time of Use</u>							
Service Charge (12 Month Sum)	144	\$ -	\$ 66.91	\$ 66.91	\$ -	\$ 9,635	\$ 9,635
On-Peak Demand	2,234.49	\$ 8.63	\$ -	\$ 8.63	\$ 19,284	\$ -	\$ 19,284
NCP Demand	8,466.81	\$ -	\$ 1.68	\$ 1.68	\$ -	\$ 14,224	\$ 14,224
Energy Charge per kWh	1,730,345	\$ 0.071776	\$ 0.000016	\$ 0.071792	\$ 124,197	\$ 28	\$ 124,225
Base Revenue					\$ 143,481	\$ 23,887	\$ 167,368
PPCA Revenue					\$ 143,481	\$ -	\$ -
Total Revenue					\$ 143,481	\$ 23,887	\$ 167,368
<u>Irrigation Pumping</u>							
Service Charge (12 Month Sum)	132	\$ -	\$ 61.76	\$ 61.76	\$ -	\$ 8,152	\$ 8,152
NCP Demand	12,025.74	\$ 5.74	\$ 1.68	\$ 7.42	\$ 69,028	\$ 20,203	\$ 89,231
Energy Charge per kWh	2,572,007	\$ 0.072027	\$ 0.010016	\$ 0.082043	\$ 185,254	\$ 25,761	\$ 211,015
Base Revenue					\$ 254,282	\$ 54,117	\$ 308,398
PPCA Revenue					\$ 254,282	\$ -	\$ -
Total Revenue					\$ 254,282	\$ 54,117	\$ 308,398
Base Revenue	4,302,352				\$ 397,763	\$ 78,004	\$ 475,766
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 397,763	\$ 78,004	\$ 475,766
3. SMALL COMMERCIAL SERVICE							
<u>Sm Comm Demand - Net Metering</u>							
Service Charge (12 Month Sum)	5	\$ -	\$ 36.03	\$ 36.03	\$ -	\$ 180	\$ 180
NCP Demand > 3 kW	73.68	\$ 6.13	\$ 4.61	\$ 10.74	\$ 452	\$ 340	\$ 791
Energy Charge per kWh	24,280	\$ 0.072753	\$ 0.000598	\$ 0.073351	\$ 1,766	\$ 15	\$ 1,781
Base Revenue					\$ 2,218	\$ 534	\$ 2,752
PPCA Revenue					\$ 2,218	\$ -	\$ -
Total Revenue					\$ 2,218	\$ 534	\$ 2,752

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.
DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate		Total	Proposed Revenue		Total
		Pur Pwr	Dist Wires		Pur Pwr	Dist Wires	
3. SMALL COMMERCIAL SERVICE (Continued)							
<u>Small Commercial Demand</u>							
Service Charge (12 Month Sum)	5,552	\$ -	\$ 36.03	\$ 36.03	\$ -	\$ 200,039	\$ 200,039
NCP Demand > 3 kW	187,060.45	\$ 6.13	\$ 4.61	\$ 10.74	\$ 1,146,681	\$ 862,349	\$ 2,009,029
Energy Charge per kWh	63,019,478	\$ 0.072753	\$ 0.000598	\$ 0.073351	\$ 4,584,856	\$ 37,686	\$ 4,622,542
Base Revenue					\$ 5,731,537	\$ 1,100,073	\$ 6,831,610
PPCA Revenue					\$ 5,731,537	\$ 1,100,073	\$ 6,831,610
Total Revenue							
					\$ 5,731,537	\$ 1,100,073	\$ 6,831,610
<u>Small Commercial Energy</u>							
Service Charge (12 Month Sum)	35,164	\$ -	\$ 17.00	\$ 17.00	\$ -	\$ 597,788	\$ 597,788
Energy Charge per kWh	38,541,431	\$ 0.087338	\$ 0.020088	\$ 0.107426	\$ 3,366,132	\$ 774,220	\$ 4,140,352
Base Revenue					\$ 3,366,132	\$ 1,372,008	\$ 4,738,140
PPCA Revenue					\$ 3,366,132	\$ 1,372,008	\$ 4,738,140
Total Revenue							
					\$ 3,366,132	\$ 1,372,008	\$ 4,738,140
<u>Small Commercial - Net Metering</u>							
Service Charge (12 Month Sum)	49	\$ -	\$ 18.50	\$ 18.50	\$ -	\$ 907	\$ 907
Energy Charge per kWh	64,010	\$ 0.087338	\$ 0.020088	\$ 0.107426	\$ 5,591	\$ 1,286	\$ 6,876
Base Revenue					\$ 5,591	\$ 2,192	\$ 7,783
PPCA Revenue					\$ 5,591	\$ 2,192	\$ 7,783
Total Revenue							
					\$ 5,591	\$ 2,192	\$ 7,783
<u>Small Commercial TOU</u>							
Service Charge (12 Month Sum)	91	\$ -	\$ 41.01	\$ 41.01	\$ -	\$ 3,732	\$ 3,732
On-Peak Demand	1,430.12	\$ 14.45	\$ -	\$ 14.45	\$ 20,665	\$ -	\$ 20,665
NCP kW	3,175.62	\$ -	\$ 4.61	\$ 4.61	\$ -	\$ 14,640	\$ 14,640
Energy Charge per kWh	1,020,044	\$ 0.045399	\$ 0.015590	\$ 0.060989	\$ 46,309	\$ 15,902	\$ 62,211
Base Revenue					\$ 66,974	\$ 34,274	\$ 101,248
PPCA Revenue					\$ 66,974	\$ 34,274	\$ 101,248
Total Revenue							
					\$ 66,974	\$ 34,274	\$ 101,248
<u>SC Energy Gov</u>							
Service Charge (12 Month Sum)	3,208	\$ -	\$ 17.00	\$ 17.00	\$ -	\$ 54,536	\$ 54,536
Energy Charge per kWh	3,559,150	\$ 0.087338	\$ 0.020088	\$ 0.107426	\$ 310,849	\$ 71,496	\$ 382,345
Base Revenue					\$ 310,849	\$ 126,032	\$ 436,881
PPCA Revenue					\$ 310,849	\$ 126,032	\$ 436,881
Total Revenue							
					\$ 310,849	\$ 126,032	\$ 436,881

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.
DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate		Pur Pwr	Proposed Revenue	
			Dist Wires			Total
3. SMALL COMMERCIAL SERVICE (Continued)						
SC Demand Gov						
Service Charge (12 Month Sum)	784	\$	\$ 36.03	\$	\$ 28,248	\$ 28,248
NCP Demand > 3 kW	26,495.68	\$	\$ 4.61	\$	\$ 122,145	\$ 284,564
Energy Charge per kWh	7,582,510	\$	\$ 0.000598	\$	\$ 4,534	\$ 556,556
Base Revenue					\$ 154,927	\$ 889,367
PPCA Revenue					\$ -	\$ -
Total Revenue				\$ 714,440	\$ 154,927	\$ 869,367
Base Revenue				\$ 10,197,740	\$ 2,790,041	\$ 12,987,781
PPCA Revenue				\$ -	\$ -	\$ -
Total Revenue	113,810,903			\$ 10,197,740	\$ 2,790,041	\$ 12,987,781
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE						
Large C&I Secondary						
Service Charge (12 Month Sum)	983	\$	\$ 175.00	\$	\$ 172,025	\$ 172,025
NCP Demand	189,369.16	\$	\$ 3.08	\$	\$ 583,257	\$ 2,062,230
Energy Charge per kWh	76,311,058	\$	\$ 0.0063682	\$	\$ 484,499	\$ 5,344,140
Base Revenue				\$ 6,338,614	\$ 1,239,781	\$ 7,578,395
PPCA Revenue				\$ -	\$ -	\$ -
Total Revenue				\$ 6,338,614	\$ 1,239,781	\$ 7,578,395
Large C&I Primary						
Service Charge (12 Month Sum)	36	\$	\$ 175.00	\$	\$ 6,300	\$ 6,300
NCP Demand	17,172.00	\$	\$ 3.08	\$	\$ 52,890	\$ 187,003
Energy Charge per kWh	8,497,320	\$	\$ 0.0063682	\$	\$ 53,949	\$ 595,076
Primary Discount on Demand & Energy			-1.00%	\$ (6,752)	\$ (1,131)	\$ (7,884)
Base Revenue				\$ 668,487	\$ 112,008	\$ 780,495
PPCA Revenue				\$ -	\$ -	\$ -
Total Revenue				\$ 668,487	\$ 112,008	\$ 780,495

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (updated to 2010)

MOHAVE ELECTRIC COOPERATIVE, INC.
DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
<u>Large C&I TOU</u>							
Service Charge (12 Month Sum)	31	\$ -	\$ 189.00	\$ 189.00	\$ -	\$ 5,859	\$ 5,859
On-Peak Demand	690.80	\$ 11.11	\$ -	\$ 11.11	\$ 7,675	\$ -	\$ 7,675
NCP kW	5,713.20	\$ -	\$ 3.08	\$ 3.08	\$ -	\$ 17,597	\$ 17,597
Energy Charge per kWh	564,880	\$ 0.045405	\$ 0.006349	\$ 0.051754	\$ 25,848	\$ 3,586	\$ 29,235
Base Revenue					\$ 33,323	\$ 27,042	\$ 60,365
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 33,323	\$ 27,042	\$ 60,365
<u>Large C&I GOV</u>							
Service Charge (12 Month Sum)	362	\$ -	\$ 175.00	\$ 175.00	\$ -	\$ 63,350	\$ 63,350
NCP Demand	64,343.36	\$ 7.81	\$ 3.08	\$ 10.89	\$ 502,522	\$ 198,178	\$ 700,699
Energy Charge per kWh	17,180,160	\$ 0.063682	\$ 0.006349	\$ 0.070031	\$ 1,094,067	\$ 109,077	\$ 1,203,144
Base Revenue					\$ 1,596,589	\$ 370,604	\$ 1,967,193
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 1,596,589	\$ 370,604	\$ 1,967,193
<u>Billed at Subtransmission Delivery Level</u>							
<u>LC&I Trans (Current TOU)</u>							
Service Charge (12 Month Sum)	12	\$ -	\$ 175.00	\$ 175.00	\$ -	\$ 2,100	\$ 2,100
NCP kW	53,106.00	\$ 7.81	\$ 3.08	\$ 10.89	\$ 414,758	\$ 163,566	\$ 578,324
Energy Charge per kWh	30,204,000	\$ 0.063682	\$ 0.006349	\$ 0.070031	\$ 1,923,451	\$ 191,765	\$ 2,115,216
Subtransmission Discount on Demand & Energy		-7.50%	-7.50%	-7.50%	\$ (175,366)	\$ (26,807)	\$ (202,173)
Base Revenue					\$ 2,162,843	\$ 330,624	\$ 2,493,468
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 2,162,843	\$ 330,624	\$ 2,493,468

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.
DEVELOPMENT OF 2010 REVENUE UNDER PROPOSED RATES

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
LP Substation Billed at Substation Delivery Level							
Service Charge (12 Month Sum)	24						
NCP kW	67,500.00	\$ -	\$ 175.00	\$ 175.00	\$ -	\$ 4,200	\$ 4,200
Energy Charge per kWh		\$ 7.81	\$ 3.08	\$ 10.89	\$ 527,175	\$ 207,900	\$ 735,075
Substation Discount on Demand & Energy	38,802,000	\$ 0.063682	\$ 0.006349	\$ 0.070031	\$ 2,470,989	\$ 246,354	\$ 2,717,343
Base Revenue		-5.00%	-5.00%	-5.00%	(149,908)	(22,923)	(172,831)
PPCA Revenue					\$ 2,848,256	\$ 435,531	\$ 3,283,787
Total Revenue					\$ -	\$ -	\$ -
					\$ 2,848,256	\$ 435,531	\$ 3,283,787
Base Revenue	171,559,418				\$ 13,648,112	\$ 2,515,591	\$ 16,163,703
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 13,648,112	\$ 2,515,591	\$ 16,163,703
5. LIGHTING SERVICE							
175 W MVL	6,039	\$ 6.13	\$ 0.98	\$ 7.11	\$ 37,019	\$ 5,918	\$ 42,937
100 W HPS	2,594	\$ 3.07	\$ 5.39	\$ 8.46	\$ 7,964	\$ 13,982	\$ 21,945
175 W MVL CO	320	\$ 6.07	\$ 0.51	\$ 6.58	\$ 1,942	\$ 163	\$ 2,106
100 W HPS CO	3,644	\$ 3.07	\$ 2.34	\$ 5.41	\$ 11,187	\$ 8,527	\$ 19,714
250 W HPS	1,211	\$ 7.81	\$ 6.14	\$ 13.95	\$ 9,458	\$ 7,436	\$ 16,893
Base Revenue	13,808				\$ 67,570	\$ 36,026	\$ 103,596
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 67,570	\$ 36,026	\$ 103,596
kWh	1,100,103						
6. RESALE REVENUE							
Base Revenue					\$ 3,222,980	\$ 475,687	\$ 3,698,667
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue	46,862,961				\$ 3,222,980	\$ 475,687	\$ 3,698,667
7. TOTAL REVENUE							
Base Revenue	702,606,696				\$ 61,208,344	\$ 16,846,408	\$ 78,054,752
PPCA Revenue					\$ -	\$ -	\$ -
Other Revenue					\$ -	\$ 919,367	\$ 919,367
Total					\$ 61,208,344	\$ 17,765,775	\$ 78,974,119

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test-Year Ended December 31, 2009 (Updated to 2010)

**MOHAVE ELECTRIC COOPERATIVE, INC.
RESIDENTIAL COMPARISON OF EXISTING MOHAVE PROPOSED AND STAFF PROPOSED RATES - 2010 USAGE**

	Existing Rate	Mohave Proposed Rate	% Change	Staff Proposed Rate	% Change
Service Charge	\$9.50	\$16.50	73.7%	\$ 12.00	26.3%
Energy Charge, per kWh					
First 400	\$0.083190	\$0.096373	15.8%	\$0.094823	14.0%
Next 600	\$0.083190	\$0.106373	27.9%	\$0.109823	32.0%
Over 1,000	\$0.083190	\$0.116373	39.9%	\$0.124823	50.0%
PPCA Factor	\$0.023685	(\$0.001850)	-107.8%	\$0.000000	-100.0%
Total Energy Charge plus PPCA					
First 400	\$0.106875	\$0.094523	-11.6%	\$0.094823	-11.3%
Next 600	\$0.106875	\$0.104523	-2.2%	\$0.109823	2.8%
Over 1,000	\$0.106875	\$0.114523	7.2%	\$0.124823	16.8%

kWh Usage	Monthly Cust ¹	Existing Rate	Mohave Proposed Rate	Mohave Change fr. Existing	Mohave % Change fr. Existing	Staff Proposed Rate	Staff Change fr. Existing	Staff % Change fr. Existing
0	1,009	\$9.50	\$16.50	\$7.00	73.68%	\$12.00	\$2.50	26.32%
100	2,913	\$20.19	\$25.95	\$5.76	28.56%	\$21.48	\$1.29	6.41%
200	2,687	\$30.88	\$35.40	\$4.53	14.67%	\$30.96	\$0.09	0.29%
400	5,213	\$52.25	\$54.31	\$2.06	3.94%	\$49.93	(\$2.32)	-4.44%
800	9,166	\$95.00	\$96.12	\$1.12	1.18%	\$93.86	(\$1.14)	-1.20%
1,000	3,212	\$116.38	\$117.02	\$0.65	0.56%	\$115.82	(\$0.55)	-0.47%
2,000	7,881	\$223.25	\$231.55	\$8.30	3.72%	\$240.65	\$17.40	7.79%
3,000	2,466	\$330.13	\$346.07	\$15.94	4.83%	\$365.47	\$35.34	10.71%
5,000	738	\$543.88	\$575.12	\$31.24	5.74%	\$615.12	\$71.24	13.10%
8,000	54	\$864.50	\$918.68	\$54.18	6.27%	\$989.58	\$125.08	14.47%
Over	4							
860 Average		\$101.41	\$102.39	\$0.98	0.96%	\$100.45	(\$0.96)	-0.95%
637 Median		\$77.58	\$79.08	\$1.50	1.94%	\$75.96	(\$1.62)	-2.09%

Note 1 - Customers with usage from the previous block to this block

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF)
MOHAVE ELECTRIC COOPERATIVE,)
INC., AN ELECTRIC COOPERATIVE)
NONPROFIT MEMBERSHIP CORPORATION)
FOR A DETERMINATION OF THE)
FAIR VALUE OF ITS PROPERTY FOR)
RATEMAKING PURPOSES, TO FIX A JUST)
AND REASONABLE RETURN THEREON AND)
TO APPROVE RATES DESIGNED TO)
DEVELOP SUCH RETURN)

DOCKET NO. E-01750A-11-0136

SURREBUTAL

TESTIMONY

OF

BENTLEY ERDWURM

CONSULTANT

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

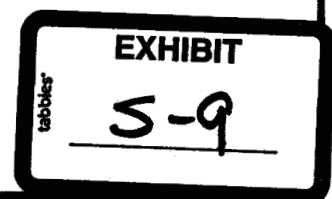


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**EXECUTIVE SUMMARY
MOHAVE ELECTRIC COOPERATIVE
DOCKET NO. E-01750A-11-0136**

This surrebuttal testimony addresses issues related to cost allocation and rate design for Mohave Electric Cooperative ("Mohave") that were addressed by Mohave's witness, Mr. Michael W. Searcy, in his rebuttal testimony. Staff recommends the following:

- The standard residential customer charge should be set at \$13.50 per month.
- The peak period recommendations for residential time-of-use as presented in Mr. Searcy's rebuttal testimony and the winter peak definition from Mr. Searcy's direct testimony should be approved.
- Mohave's proposed inverted blocking structure for residential time of use should be approved, subject to the condition that the cents per kWh block differential matches the block differential approved for the regular residential rate.
- There should be a \$5.00 differential between the customer charges of the standard residential rate and the residential time-of-use rates.
- The existing Large Commercial and Industrial Time-of-Use rate schedule should be frozen for new customers. The frozen rate should be eliminated in Mohave's next general rate case.

1 **INTRODUCTION**

2 **Q. Please state your name, occupation, and business address.**

3 A. My name is Bentley Erdwurm. I am a Consultant employed by the Arizona Corporation
4 Commission ("Commission") in the Utilities Division ("Staff"). My business address is
5 1200 West Washington Street, Phoenix, Arizona 85007.

6
7 **Q. Did you also prepare pre-filed direct testimony in this proceeding on behalf of the**
8 **Commission Staff?**

9 A. Yes.

10
11 **Q. What is the scope of this testimony?**

12 A. I will address issues related to cost allocation and rate design for Mohave Electric
13 Cooperative ("Mohave") that were addressed by Mohave's witness, Mr. Michael W.
14 Searcy, in his rebuttal testimony. Areas that I address include (1) residential rate design
15 (the residential customer charge and inclining block rate structure), (2) the residential
16 time-of-use ("TOU") rate design, (3) customer charges applicable to other sub-classes of
17 customers that are tied to the residential and residential time-of-use customer charges, and
18 (4) the design of the Large Commercial and Industrial Time-of-Use ("LC&I TOU") rate.

19
20 **RESIDENTIAL RATE DESIGN**

21 **Q. Please discuss your recommendations related to the residential customer charge and**
22 **residential rate design, detailing how they compare to Mr. Searcy's**
23 **recommendations and to your recommendations in direct testimony.**

24 A. Staff modifies its recommendation for the standard residential customer charge, increasing
25 the Staff-proposed charge to \$13.50 per month, as opposed to the \$12.00 charge
26 recommended in my direct testimony. Mr. Searcy proposed a \$16.50 charge in his direct

1 testimony, and has recommended an escalating charge in his rebuttal testimony. Mr.
2 Searcy's rebuttal proposal escalates the customer charge from an initial \$12.00 (to match
3 the recommendation from Staff's direct testimony) to \$16.50 by November 2014. The
4 current residential customer charge is \$9.50 per month. Staff does not support the phase-
5 in of a residential customer charge in excess of \$13.50 in advance of Mohave's next
6 general rate case. A phase-in rate would be administratively burdensome, and Mohave
7 would be required to provide notice to its customers for each rate adjustment. Moreover,
8 phase-in of increased customer charges would require simultaneous decreases in kWh
9 (energy) charges to conform to the approved revenue target, unless Mohave would opt to
10 accept the lower kWh charges from the point of rate implementation.

11
12 Staff maintains its direct testimony recommendation for an inclining block rate design
13 with a 1.5 cent (15 mills) escalation in the price per kWh between the rate blocks, and Mr.
14 Searcy indicates in his rebuttal testimony that the 15 mill block differential is acceptable
15 to Mohave. The inclining block structure, characterized by unit prices rising with usage
16 levels, helps mitigate bill impacts for customers with "basic needs" usage levels and
17 encourages the prudent and economic use of scarce resources.

18
19 Mr. Searcy implies that Staff's residential customer charge recommendation in direct
20 testimony was driven solely by bill impact considerations and that Staff seeks to modify
21 the cost of service study to justify the customer charge recommendation (Searcy Rebuttal,
22 page 16 line 37 through page 17 line 4). On the contrary, Staff's customer charge
23 recommendation was driven by a costing methodology restricting the customer-related
24 classification to metering, meter-reading, the service drop, billing and customer service.
25 Customer impact may place an upper limit on customer charge increases.

1 **Q. Why is Staff now recommending a higher residential customer charge of \$13.50, as**
2 **opposed to the \$12.00 supported in direct testimony?**

3 A. Staff believes that a \$13.50 monthly residential customer charge - while in excess of the
4 levels associated with metering, meter-reading, the service drop, billing and customer
5 service - is reasonable given Mohave's acceptance of the inclining rate structure with a 15
6 mill block differential. In effect, the customer charge and the block structure are a
7 "package deal." Additionally, Mr. Searcy has described how a less dense system
8 (typically a more rural service territory) must install poles, wire and transformers that may
9 serve only a few customers, and that some minimum size of poles and wire and
10 transformer must be used. This is a valid observation when customers are in isolated
11 areas. Mr. Searcy explains why he believes that a customer component related to poles,
12 wires and transformers is necessary for this less dense system. Staff believes that *for some*
13 *utilities*, circumstances may justify *some* customer component for poles, lines and
14 transformers in its cost study; however, the magnitude of the customer component for
15 these items has not been supported for Mohave in this proceeding. Even in rural systems,
16 not all customers are isolated, and the rationale for a customer-related classification for
17 poles, lines and transformers may be non-existent for these customers. To the extent that
18 the number of customers in dense areas is higher than the number of customers in isolated
19 areas, the magnitude of the customer-related component for poles, lines and transformers
20 will be reduced or eliminated. Are isolated customers the exception or the rule on the
21 Mohave system? More study is required.

22
23 Given that higher customer charges may have adverse bill impacts on bills for "basic
24 needs" levels, and may be contrary to providing incentives supporting the prudent use of
25 energy, Staff contends that the default position in future Mohave rate cases should be that

1 no portion of poles, lines and transformers is classified as customer-related without some
2 study supporting the magnitude of customer component.

3
4 Mr. Searcy has noted in his direct testimony and Staff here acknowledges that Decision
5 No. 71230 included language that customer service costs include "the customer
6 component of distribution line expense, a portion of transformer expense, [in addition to]
7 the meter, service drop expense and meter reading and customer records expenses."
8 However, Decision No. 71230 applied to Trico, not to Mohave and not to other utilities.
9 Staff contends that the aforementioned "customer component of distribution line expense"
10 is for many utility systems - especially denser systems - more phantom than substance.
11 Staff notes that utilities - both those with more dense territories and those with less dense
12 territories - typically view rate stability as desirable, that higher residential customer
13 charges typically promote rate stability, and that higher residential customer charges may
14 be supported, rightly or wrongly, through classifying as customer-related a portion of
15 poles, lines and transformers. Any use of a customer classification for poles, lines and
16 transformers must be justified, and regardless of the results of the cost study, the
17 Commission is not compelled to base any specific class rate design solely on the cost
18 study. Staff's direct testimony discusses other criteria that can influence rate design.

19
20 Mohave is characterizing the implementation of a residential customer charge less than
21 \$16.50 as placing it at risk for not recovering fixed costs. Clearly, revenue stability is
22 enhanced when customer charges are used to collect a larger percentage of revenue
23 (assuming the typical situation where the number of customers varies less than demand or
24 energy billing determinants). However, just as Mohave contends that customer charge
25 levels should not be driven predominately by customer impact considerations; Staff

1 contends that these charges should not be driven predominately by revenue stability
2 considerations.

3
4 **RESIDENTIAL TIME-OF-USE**

5 **Q. Please discuss your residential time-of-use recommendations.**

6 A. The residential time-of use rate design involves several issues where Staff's and Mohave's
7 recommendations differed in direct testimony. The key issue for Staff raised in direct
8 testimony was the length of the summer peak period. Specifically, Staff recommended
9 that the summer peak period contain fewer hours than proposed by Mohave in direct
10 testimony. Mr. Searcy in his rebuttal testimony modified his summer peak hour definition
11 to be closer to Staff's recommendation. This resolution now allows Staff to recommend
12 acceptance of other residential time-of-use rate features proposed by Mohave, including
13 the specifics of the inclining rate structure and the customer charge differential relative to
14 the standard residential time-of-use rate.

15
16 **Q. Please discuss the length of the summer peak period in the residential time-of-use**
17 **rate.**

18 A. The Staff recommended in its direct testimony that the number of peak hours in Mohave's
19 residential time-of-use rate be reduced. Typically, shorter peak periods are more effective
20 at controlling coincident peak demand spikes in Arizona's desert climate.

21
22 Additionally, Mohave has proposed two residential time-of-use options: one option
23 (Option 1; peak on weekdays only) restricts peak hours to weekdays (Monday-Friday)
24 only, and the other (Option 2; peak applies to weekdays and weekends) includes both
25 weekday and weekend peak hours. Customers would be able to choose which time-of-use
26 option they want. Staff in direct testimony supported the use of the same peak hours in

1 both options, with the rates differentiated by pricing. Mohave supported a shorter peak
2 period for the weekend option so that they could publicize the weekend option as having
3 the same number of peak hours in the week. Mohave believes that customers would be
4 more accepting of the Option 2 rate (peak applies to weekdays and weekends) if the
5 number of peak hours under Option 2 does not exceed the Option 1 rate (where peak
6 applies to weekdays only). That is, customers may focus more on the peak period
7 definition than on pricing details. Staff agrees that this is a reasonable argument and
8 recommends that the Commission approve differing peak periods for Options 1 and 2 as
9 recommended in Mr. Searcy's rebuttal testimony.

10
11 For Mohave's proposed Residential time-of-use Option 1 (peak on weekdays only),
12 Mohave in direct testimony designated the summer (April 16-October 15) peak period as
13 12:00 p.m. (noon) to 9:00 p.m. (9 hours). Under proposed Option 2, (peak applies
14 weekdays and weekends), Mohave in direct testimony designated the summer peak period
15 as 2:00 p.m. to 8:30 p.m. (6.5 hours). Staff in its direct testimony recommended that the
16 summer peak period for both options end at 7:30 p.m., and that it begin no earlier than
17 1:00 p.m. for either option. Either 1:00 p.m. or 2:00 p.m. is an appropriate summer peak
18 start time under either option. Staff's primary aim in direct testimony was to reduce the
19 length of the summer peak period.

20
21 Mr. Searcy in rebuttal for Mohave presented a compromise position that shortened the
22 summer peak period for both residential time-of-use Options 1 and 2. Mohave's revised
23 proposal for Residential time-of-use Option 1 (peak on weekdays only) designates the
24 summer (April 16-October 15) peak period as 12:00 p.m. (noon) to 7:30 p.m. (7.5 hours).
25 Revised proposed Option 2, (peak applies weekdays and weekends), designates the
26 summer peak period as 2:00 p.m. to 7:30 p.m. (5.5 hours) (Searcy rebuttal testimony page

1 24, lines 21-29). The shorter peak periods are appropriate and Staff supports Commission
2 approval of Mohave's peak period recommendations as presented in Mr. Searcy's rebuttal
3 testimony. Mohave's proposed winter peak definition from Mr. Searcy's direct testimony
4 is acceptable to Staff.

5
6 **Q. Please discuss the inclining block rate structure in the residential time-of-use rate.**

7 A. In direct testimony, Mohave recommended an inclining block structure allowing more
8 TOTAL kWh in the lower (and less expensive) blocks than the level of kWh allowed in
9 lower blocks in the regular residential rates. Staff in direct testimony recommended an
10 "adder" of "x cents" per kWh applicable to the first 400 kWh of monthly usage (which
11 first-block adder would result on a credit per kWh for the 1st 400 kWh of monthly usage),
12 an adder of "x+\$0.015" per kWh for the next 600 kWh, and an adder of "x+\$0.030" per
13 kWh for the consumption in excess of 1000 kWh (which third-block adder would result on
14 a credit per kWh for the 1st 400 kWh of monthly usage). Staff's design from direct
15 testimony best mimics the inclining block mechanism of the regular residential rate in that
16 a time-of use customer buys the same number of kWh in a block as a regular residential
17 customer. In contrast, Mohave's proposed inverted block structure offers first block
18 pricing for both the first 400 kWh of monthly on-peak kWh and for the first 400 kWh of
19 monthly off-peak kWh. As such, a customer could purchase more than 400 kWh of total
20 (peak and off-peak combined) first block (lower priced) kWh. Mohave's proposal to offer
21 more lower-priced, lower-block kWh to time-of-use residential customers makes time-of-
22 use more attractive to potential subscribers, especially higher-use customers who
23 otherwise would purchase a significant portion of energy in the more expensive third
24 block of the regular (non-time-of-use) residential rate. The appeal of the time-of-use rate
25 to higher-use customers is further enhanced because these customers have more end-uses
26 (e.g., pool pumping or significant air conditioning use) that can be curtailed in whole or in

1 part, and more potential for load shifting. Providing incentives for high-use customers to
2 move load away from peak periods benefits all customers on the system.

3
4 Staff realizes that Mohave's proposed blocking mechanism is simpler and easier to
5 explain to customers than the blocking mechanism presented in the Staff direct testimony.
6 Staff is persuaded that Mohave's position on the inclining block mechanism is preferred to
7 Staff's direct testimony position on residential time-of use blocking. Mohave's blocking
8 design makes the residential time-of-use program more attractive to potential subscribers,
9 and will promote subscription of a program that benefits all customers by reducing energy
10 use at peak times. Staff recommends approval of Mohave's inverted blocking structure
11 subject to the condition that the cents per kWh block differential will match the block
12 differential approved for the regular residential rate (which under Staff's proposal is 15
13 mills per kWh (1.5 cents per kWh) between adjacent blocks, for a total differential of 3.0
14 cents per kWh).

15
16 **Q. Please discuss Mohave's proposed \$5.00 differential between the customer charge in**
17 **the standard residential rate and the customer charge in the residential time-of-use**
18 **rate.**

19 **A.** Staff recommended in direct testimony that the customer charge differential be set at
20 \$3.00 (i.e., the time-of-use customer charge exceeds the regular residential customer
21 charge by \$3.00). However, further review of differential in the costs of specific meters
22 used by Mohave (\$125 for the standard residential meter vs. \$449 for the meter for time-
23 of-use installations) plus Mohave's documentation of additional costs related to time-of-
24 use for customer service, installation, meter reading, billing and accounting indicates that
25 the \$5.00 differential is cost-justified. In conjunction with other promotional features of
26 the time of use program (such as availability of two residential time-of-use options and

1 time-of use customers' ability to purchase more lower block, less expensive energy), Staff
2 is satisfied that subscription to and acceptance of the time-of-use program should not be
3 adversely affected by the larger \$5.00 differential. Therefore Staff recommends approval
4 of a \$5.00 differential between the customer charges of the standard residential rate and
5 the residential time-of-use rates.
6

7 **LARGE COMMERCIAL AND INDUSTRIAL TIME-OF-USE RATE DESIGN**

8 **Q. Please discuss your recommendation for the Large Commercial and Industrial Time-**
9 **of-Use ("LC"& "I TOU") rate.**

10 A. During the test-year, the existing LC&I TOU rate served three customers around 565,000
11 kWh. To put this in perspective, a large residential customer averaging 3,000 kWh per
12 month would use 36,000 kWh in a year, and the annual consumption of the three LC&I
13 TOU customers would equate in usage to only 16 of the large residential customers.
14 Viewed another way, LC&I TOU revenue in the test year was less than one part out of a
15 thousand in Mohave system revenue. Finally, the three test-year LC&I TOU customers
16 have significantly different load profiles than typical Large Commercial and Industrial
17 customers on the Mohave system.
18

19 As explained in Staff direct testimony, Mohave's proposed revision to the LC&I TOU rate
20 as presented in Mr. Searcy's direct testimony is well-reasoned and cost-based. The
21 Mohave proposal here is a huge improvement over the existing design of the LC&I TOU
22 rate. Under the existing design, LC&I TOU customers can avoid contributing for
23 capacity-related facilities by controlling their peak demand (highest kW) during the on-
24 peak period. While shifting load from on-peak periods to off-peak periods provides
25 benefits to the system, off-peak users must still contribute for downstream costs that their

1 off-peak load helps create. Otherwise, the off-peak user "free rides" on the system and
2 other customers must pick up costs created by the free rider.

3
4 Moving from the existing LC&I TOU rate to Mohave's proposed LC&I TOU would result
5 in a bill increase of over 40% to existing LC&I TOU customers. Staff in direct testimony
6 focused on mitigating this percentage increase, and recommended an LC&I TOU rate with
7 an on-peak demand charge of \$11.11 per kW-month, substantially lower than Mohave's
8 proposed \$23.00 per kW-month. This change reduced the percentage increase to the three
9 existing LC&I TOU customers to around 27%.

10
11 In retrospect, the substantial reduction in the on-peak demand charge will mean that
12 subscribers to LC&I TOU will pay too little for service relative to other customers, which
13 is unfair to the other customers. If such a non-compensatory LC&I TOU rate were
14 approved and implemented, substantial LC&I load could migrate to the time-of-use
15 option, and more customers and larger loads would seek to have the windfall
16 grandfathered for as long as possible. Initially, Mohave could suffer substantial margin
17 losses, and over the longer run (after Mohave's next rate case) other customers could be
18 burdened with the costs imposed by LC&I TOU customers because of the potential the
19 windfall could be grandfathered.

20
21 Staff believes a simple and fair solution is to grandfather the three existing LC&I TOU
22 customers (customers must be on the rate as of March 1, 2012) onto a frozen LC&I
23 TOU(F) rate with the \$11.11 on-peak demand charge (the Staff direct LC&I TOU rate
24 conformed to a minor system revenue change), as shown in Exhibit DBE-3. Staff
25 proposes that the frozen rate be eliminated in Mohave's next general rate case. The three

1 customers on the frozen rate would then need to choose between the regular LC&I rate
2 and the LC&I TOU rate (the rate generally available).

3
4 Staff opposes Mohave's recommendation in rebuttal to phase-in higher on-peak demand
5 charges for the three existing LC&I customers. The impact on Mohave's revenue is trivial
6 and could not justify the administrative burdens of the phase-in.

7
8 **SUMMARY OF RECOMMENDATIONS**

9 **Q. Please summarize Staff's surrebuttal recommendations.**

10 **A.** Staff's recommendations are the following:

- 11 • The standard residential customer charge should be set at \$13.50 per month.
12 • The peak period recommendations for residential time-of-use as presented in Mr. Searcy's
13 rebuttal testimony and the winter peak definition from Mr. Searcy's direct testimony
14 should be approved.
15 • Mohave's proposed inverted blocking structure for residential time of use should be
16 approved, subject to the condition that the cents per kWh block differential matches the
17 block differential approved for the regular residential rate.
18 • There should be a \$5.00 differential between the customer charges of the standard
19 residential rate and the residential time-of-use rates.
20 • The existing Large Commercial and Industrial Time-of-Use rate schedule should be frozen
21 for new customers. The frozen rate should be eliminated in Mohave's next general rate
22 case.

23
24 **Q. Does this conclude your surrebuttal testimony?**

25 **A.** Yes, it does.

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND STAFF SURREBUTTAL RATES

	Cust	kWh		Adjusted 2010	Mohave Prop. Direct		Change		Staff Surrebittal		Change	
		Total	Avg Mn		2010		\$	%	2010		\$	%
Residential	34,875	364,970,959	872	42,986,712	44,735,329		1,748,617	4.07%	44,715,743		1,729,031	4.02%
Irrigation Time of Use	12	1,730,345	12,016	166,306	168,026		1,720	1.03%	167,368		1,062	0.64%
Irrigation Pumping	11	2,572,007	19,485	302,194	309,962		7,768	2.57%	308,398		6,204	2.05%
Subtotal Irrigation	23	4,302,352	15,588	468,500	477,988		9,488	2.03%	475,766		7,266	1.55%
Small Comm Energy	3,201	42,164,591	1,098	4,900,351	5,177,391		277,040	5.65%	5,224,497		324,146	6.61%
Small Comm Demand	529	70,626,268	11,126	7,389,210	7,729,118		339,908	4.60%	7,720,820		331,610	4.49%
Small Comm TOU	8	1,020,044	10,625	96,177	100,936		4,759	4.95%	101,502		5,326	5.54%
Subtotal Small Comm	3,738	113,810,903	2,537	12,385,738	13,007,445		621,707	5.02%	13,046,819		661,081	5.34%
Large Comm & Industrial	118	170,994,538	4,495,062	15,775,430	16,108,634		333,204	2.11%	16,160,593		385,163	2.44%
LC& TOU	3	564,880	15,691	48,035	67,443		19,408	40.40%	61,177		13,142	27.36%
Lighting Devices	* 1,151	1,100,103	80	98,025	103,184		5,159	5.26%	103,596		5,571	5.68%
Resale	* 1	46,862,961	3,905,247	3,698,667	3,698,667		0	0.00%	3,698,667		0	0.00%
Total Energy Sales	* 38,757	702,606,696	1,511	75,461,107	78,198,690		2,737,583	3.63%	78,262,361		2,801,253	3.71%
Other Revenue				606,899	863,547		256,647	42.29%	867,282		260,383	42.90%
Total Revenue				76,068,007	79,062,237		2,994,230	3.94%	79,129,643		3,061,636	4.02%

* Total Customers excludes Lighting Devices and Resale

MOHAVE ELECTRIC COOPERATIVE, INC.

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES (DETAIL)

	Cust	kWh		Adjusted 2010	Cents per kWh	Mohave		Cents per kWh	Change under Mohave Proposal		Staff Proposed 2010	Cents per kWh	Change under Staff Proposal	
		Total	Avg Mn			Proposed 2010			\$	%			\$	%
Residential	34,775	364,111,753	873	\$ 42,878,813	11.8	\$ 44,621,441	12.3	\$ 1,742,628	4.06%		\$ 44,602,308	12.2	\$ 1,723,495	4.02%
Residential - Seasonal	1	549	46	\$ 164	29.9	\$ 235	42.8	\$ 71	43.29%		\$ 202	36.8	\$ 38	23.15%
Residential - Net Metering	72	640,060	741	\$ 81,352	12.7	\$ 86,113	13.5	\$ 4,761	5.85%		\$ 86,089	13.5	\$ 4,737	5.82%
Res - Gov	27	218,597	675	\$ 26,383	12.1	\$ 27,540	12.6	\$ 1,157	4.38%		\$ 27,144	12.4	\$ 761	2.88%
Residential	34,875	364,970,959	872	\$ 42,986,712	11.8	\$ 44,735,329	12.3	\$ 1,748,617	4.07%		\$ 44,715,743	12.3	\$ 1,729,031	4.02%
Irrigation Time of Use	12	1,730,345	12,016	\$ 166,306	9.6	\$ 168,026	9.7	\$ 1,720	1.03%		\$ 167,368	9.7	\$ 1,062	0.64%
Irrigation Pumping	11	2,572,007	19,485	\$ 302,194	11.7	\$ 309,982	12.1	\$ 7,768	2.57%		\$ 308,398	12.0	\$ 6,204	2.05%
Subtotal Irrigation	23	4,302,352	15,588	\$ 468,500	10.9	\$ 477,988	11.1	\$ 9,488	2.03%		\$ 475,766	11.1	\$ 7,266	1.55%
Small Commercial Energy	2,930	38,541,431	1,096	\$ 4,479,803	11.6	\$ 4,733,078	12.3	\$ 253,275	5.65%		\$ 4,776,317	12.4	\$ 296,514	6.62%
SC Energy Gov	267	3,559,150	1,111	\$ 413,221	11.6	\$ 436,237	12.3	\$ 23,016	5.57%		\$ 440,348	12.4	\$ 27,126	6.56%
SC Energy - Net Metering	4	64,010	1,334	\$ 7,327	11.4	\$ 8,076	12.6	\$ 749	10.22%		\$ 7,832	12.2	\$ 505	6.89%
Small Comm Energy	3,201	42,164,591	1,098	\$ 4,900,351	11.6	\$ 5,177,391	12.3	\$ 277,040	5.65%		\$ 5,224,497	12.4	\$ 324,146	6.61%
Small Commercial Demand	463	63,019,478	11,343	\$ 6,561,332	10.4	\$ 6,854,527	10.9	\$ 293,195	4.47%		\$ 6,846,574	10.9	\$ 285,242	4.35%
SC Demand Gov	65	7,582,510	9,721	\$ 825,265	10.9	\$ 871,832	11.5	\$ 46,567	5.64%		\$ 871,487	11.5	\$ 46,222	5.60%
SC Demand - Net Metering	1	24,280	1,126	\$ 2,613	10.8	\$ 2,759	11.4	\$ 146	5.58%		\$ 2,758	11.4	\$ 145	5.56%
Small Comm Demand	529	70,626,268	11,126	\$ 7,389,210	10.5	\$ 7,729,118	10.9	\$ 339,908	4.60%		\$ 7,720,820	10.9	\$ 331,610	4.49%
Small Comm TOU	8	1,020,044	10,625	\$ 96,177	9.4	\$ 100,936	9.9	\$ 4,759	4.95%		\$ 101,502	10.0	\$ 5,326	5.54%
Subtotal Small Comm	3,738	113,810,903	2,537	\$ 12,385,738	10.9	\$ 13,007,445	11.4	\$ 621,707	5.02%		\$ 13,046,819	11.5	\$ 661,081	5.34%
Large Power Sec	82	76,311,058	77,552	\$ 7,200,844	9.4	\$ 7,578,027	9.9	\$ 377,183	5.24%		\$ 7,606,509	10.0	\$ 405,665	5.63%
LP Gov	30	17,180,160	47,723	\$ 1,842,672	10.7	\$ 1,963,366	11.4	\$ 120,694	6.55%		\$ 1,976,562	11.5	\$ 133,890	7.27%
Large Power Primary	3	8,497,320	236,037	\$ 758,514	8.9	\$ 781,262	9.2	\$ 22,748	3.00%		\$ 783,052	9.2	\$ 24,538	3.23%
LP Subtransmission	1	30,204,000	2,517,000	\$ 2,625,974	8.7	\$ 2,493,869	8.3	\$ (132,105)	-5.03%		\$ 2,500,932	8.3	\$ (125,042)	-4.76%
LP Substation	2	38,802,000	1,616,750	\$ 3,347,425	8.6	\$ 3,292,110	8.5	\$ (55,315)	-1.65%		\$ 3,293,539	8.5	\$ (53,887)	-1.61%
Large Comm & Industrial	118	170,994,538	4,495,062	\$ 15,775,430	9.2	\$ 16,108,634	9.4	\$ 333,204	2.11%		\$ 16,160,593	9.5	\$ 385,163	2.44%
LC&I TOU	3	564,880	15,691	\$ 48,035	8.5	\$ 67,443	11.9	\$ 19,408	40.40%		\$ 61,177	10.8	\$ 13,142	27.36%
Lighting Devices	1,151	1,100,103	80	\$ 98,025	8.9	\$ 103,184	9.4	\$ 5,159	5.26%		\$ 103,596	9.4	\$ 5,571	5.68%
Resale	1	46,862,961	3,905,247	\$ 3,698,667	7.9	\$ 3,698,667	7.9	\$ -	0.00%		\$ 3,698,667	7.9	\$ -	0.00%
Total Energy Sales	38,757	702,606,696	1,511	\$ 75,461,107	10.7	\$ 78,198,690	11.1	\$ 2,737,583	3.63%		\$ 78,262,361	11.1	\$ 2,801,253	3.71%
Other Revenue				\$ 606,899		\$ 863,547		\$ 256,647	42.29%		\$ 867,282		\$ 260,383	42.90%
Total Revenue				\$ 76,068,007		\$ 79,062,237		\$ 2,994,230	3.94%		\$ 79,129,643		\$ 3,061,636	4.02%

* Total Customers excludes Lighting Devices and Resale

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	Billing Units	Proposed Rate		Proposed Revenue	
		Pur Pwr	Dist Wires	Pur Pwr	Dist Wires
1. RESIDENTIAL SERVICE	108				
Residential					
Service Charge (12 Month Sum)	417,302	\$	13.50	\$	5,633,577
Energy Charge per kWh					
First 200 kWh per month	75,441,637	\$	0.079958	\$	6,032,162
Next 200 kWh per month	62,783,417	\$	0.013393	\$	5,020,036
Next 200 kWh per month	50,237,165	\$	0.014893	\$	4,695,065
Next 200 kWh per month	39,197,460	\$	0.014893	\$	3,663,316
Next 200 kWh per month	30,436,462	\$	0.014893	\$	2,844,531
Next 200 kWh per month	106,015,612	\$	0.016393	\$	11,339,218
Over 1,000 kWh per month	364,111,753	\$	0.016393	\$	33,594,329
Base Revenue				\$	11,007,979
PPCA Revenue				\$	-
Total Revenue				\$	44,602,308
Residential - Seasonal					
Service Charge (12 Month Sum)	11	\$	13.50	\$	149
Energy Charge per kWh					
First 200 kWh per month	201	\$	0.079958	\$	16
Next 200 kWh per month	200	\$	0.013393	\$	3
Next 200 kWh per month	148	\$	0.014893	\$	2
Next 200 kWh per month	0	\$	0.014893	\$	-
Next 200 kWh per month	0	\$	0.014893	\$	-
Next 200 kWh per month	0	\$	0.016393	\$	-
Over 1,000 kWh per month	549	\$	0.016393	\$	156
Base Revenue				\$	-
PPCA Revenue				\$	-
Total Revenue				\$	202

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
108							
1. RESIDENTIAL SERVICE (Continued)							
Residential - Net Metering							
Service Charge (12 Month Sum)	863	\$	\$ 19.00	\$ 19.00	\$	\$ 16,397	\$ 16,397
Energy Charge per kWh							
First 200 kWh per month	114,805	\$ 0.079958	\$ 0.013393	\$ 0.093351	\$ 9,180	\$ 1,538	\$ 10,717
Next 200 kWh per month	97,201	\$ 0.079958	\$ 0.013393	\$ 0.093351	\$ 7,772	\$ 1,302	\$ 9,074
Next 200 kWh per month	79,816	\$ 0.093458	\$ 0.014893	\$ 0.108351	\$ 7,459	\$ 1,189	\$ 8,648
Next 200 kWh per month	63,706	\$ 0.093458	\$ 0.014893	\$ 0.108351	\$ 5,954	\$ 949	\$ 6,903
Next 200 kWh per month	49,825	\$ 0.093458	\$ 0.014893	\$ 0.108351	\$ 4,657	\$ 742	\$ 5,399
Over 1,000 kWh per month	234,706	\$ 0.106958	\$ 0.016393	\$ 0.123351	\$ 25,104	\$ 3,848	\$ 28,951
Base Revenue	640,060				\$ 60,125	\$ 25,963	\$ 86,089
PPCA Revenue					\$	\$	\$
Total Revenue					\$ 60,125	\$ 25,963	\$ 86,089
Res - Gov							
Service Charge (12 Month Sum)	318	\$	\$ 13.50	\$ 13.50	\$	\$ 4,293	\$ 4,293
Energy Charge per kWh							
First 200 kWh per month	60,246	\$ 0.079958	\$ 0.013393	\$ 0.093351	\$ 4,817	\$ 807	\$ 5,624
Next 200 kWh per month	44,692	\$ 0.079958	\$ 0.013393	\$ 0.093351	\$ 3,573	\$ 599	\$ 4,172
Next 200 kWh per month	28,446	\$ 0.093458	\$ 0.014893	\$ 0.108351	\$ 2,659	\$ 424	\$ 3,082
Next 200 kWh per month	20,173	\$ 0.093458	\$ 0.014893	\$ 0.108351	\$ 1,885	\$ 300	\$ 2,186
Next 200 kWh per month	15,693	\$ 0.093458	\$ 0.014893	\$ 0.108351	\$ 1,467	\$ 234	\$ 1,700
Over 1,000 kWh per month	49,347	\$ 0.106958	\$ 0.016393	\$ 0.123351	\$ 5,278	\$ 809	\$ 6,087
Base Revenue	218,597				\$ 19,679	\$ 7,465	\$ 27,144
PPCA Revenue					\$	\$	\$
Total Revenue					\$ 19,679	\$ 7,465	\$ 27,144
Base Revenue	364,970,959				\$ 33,674,179	\$ 11,041,564	\$ 44,715,743
PPCA Revenue					\$	\$	\$
Total Revenue					\$ 33,674,179	\$ 11,041,564	\$ 44,715,743

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108	Billing Units	Proposed Rate		Proposed Revenue		
		Pur Pwr	Dist Wires	Pur Pwr	Dist Wires	Total
2. IRRIGATION SERVICE						
<u>Irrigation Time of Use</u>						
	144	\$ -	\$ 66.91	\$ -	\$ 9,635	\$ 9,635
Service Charge (12 Month Sum)	2,234.49	\$ 8.63	\$ -	\$ 19,284	\$ -	\$ 19,284
On-Peak Demand	8,466.81	\$ -	\$ 1.68	\$ -	\$ 14,224	\$ 14,224
NCP Demand	1,730,345	\$ 0.071776	\$ 0.000016	\$ 124,197	\$ 28	\$ 124,225
Energy Charge per kWh				\$ 143,481	\$ 23,887	\$ 167,368
Base Revenue					\$ -	\$ -
PPCA Revenue				\$ 143,481	\$ 23,887	\$ 167,368
Total Revenue						
<u>Irrigation Pumping</u>						
	132	\$ -	\$ 61.76	\$ -	\$ 8,152	\$ 8,152
Service Charge (12 Month Sum)	12,025.74	\$ 5.74	\$ 1.68	\$ 69,028	\$ 20,203	\$ 89,231
NCP Demand	2,572,007	\$ 0.072027	\$ 0.010016	\$ 185,254	\$ 25,761	\$ 211,015
Energy Charge per kWh				\$ 254,282	\$ 54,117	\$ 308,398
Base Revenue					\$ -	\$ -
PPCA Revenue				\$ 254,282	\$ 54,117	\$ 308,398
Total Revenue						
	4,302,352			\$ 397,763	\$ 78,004	\$ 475,766
Base Revenue					\$ -	\$ -
PPCA Revenue				\$ 397,763	\$ 78,004	\$ 475,766
Total Revenue				\$ 397,763	\$ 78,004	\$ 475,766
3. SMALL COMMERCIAL SERVICE						
<u>Sm Comm Demand - Net Metering</u>						
	5	\$ -	\$ 36.03	\$ -	\$ 180	\$ 180
Service Charge (12 Month Sum)	73.68	\$ 6.13	\$ 4.69	\$ 452	\$ 346	\$ 797
NCP Demand > 3 kW	24,280	\$ 0.072753	\$ 0.000598	\$ 1,766	\$ 15	\$ 1,781
Energy Charge per kWh				\$ 2,218	\$ 540	\$ 2,758
Base Revenue					\$ -	\$ -
PPCA Revenue				\$ 2,218	\$ 540	\$ 2,758
Total Revenue						

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (updated to 2010)

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	Billing Units	Proposed Rate		Proposed Revenue	
		Pur Pwr	Dist Wires	Pur Pwr	Dist Wires
108					
3. SMALL COMMERCIAL SERVICE (Continued)					
<u>Small Commercial Demand</u>					
Service Charge (12 Month Sum)	5,552	\$ -	\$ 36.03	\$ -	\$ 200,039
NCP Demand > 3 kW	187,060.45	\$ 6.13	\$ 4.69	\$ 1,146,681	\$ 877,314
Energy Charge per kWh	63,019,478	\$ 0.072753	\$ 0.000598	\$ 4,584,856	\$ 37,686
Base Revenue				\$ 5,731,537	\$ 1,115,038
PPCA Revenue				\$ -	\$ -
Total Revenue				\$ 5,731,537	\$ 1,115,038
<u>Small Commercial Energy</u>					
Service Charge (12 Month Sum)	35,164	\$ -	\$ 18.50	\$ -	\$ 650,534
Energy Charge per kWh	38,541,431	\$ 0.087338	\$ 0.019710	\$ 3,366,132	\$ 759,652
Base Revenue				\$ 3,366,132	\$ 1,410,186
PPCA Revenue				\$ -	\$ -
Total Revenue				\$ 3,366,132	\$ 1,410,186
<u>Small Commercial - Net Metering</u>					
Service Charge (12 Month Sum)	49	\$ -	\$ 20.00	\$ -	\$ 980
Energy Charge per kWh	64,010	\$ 0.087338	\$ 0.019710	\$ 5,591	\$ 1,262
Base Revenue				\$ 5,591	\$ 2,242
PPCA Revenue				\$ -	\$ -
Total Revenue				\$ 5,591	\$ 2,242
<u>Small Commercial TOU</u>					
Service Charge (12 Month Sum)	91	\$ -	\$ 41.01	\$ -	\$ 3,732
On-Peak Demand	1,430.12	\$ 14.45	\$ -	\$ 20,665	\$ -
NCP kW	3,175.62	\$ -	\$ 4.69	\$ -	\$ 14,894
Energy Charge per kWh	1,020,044	\$ 0.045399	\$ 0.015590	\$ 46,309	\$ 15,902
Base Revenue				\$ 66,974	\$ 34,528
PPCA Revenue				\$ -	\$ -
Total Revenue				\$ 66,974	\$ 34,528
<u>SC Energy Gov</u>					
Service Charge (12 Month Sum)	3,208	\$ -	\$ 18.50	\$ -	\$ 59,348
Energy Charge per kWh	3,559,150	\$ 0.087338	\$ 0.019710	\$ 310,849	\$ 70,151
Base Revenue				\$ 310,849	\$ 129,499
PPCA Revenue				\$ -	\$ -
Total Revenue				\$ 310,849	\$ 129,499

Follows Structure of Mohave's Supplemental Schedule N-1.0

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108	Billing Units	Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
Large C&I TOU-F (Proposed to be available only to customers subscribing to Large C&I TOU as of 03/01/2012)							
Service Charge (12 Month Sum)	31	\$ -	\$ 189.00	\$ 189.00	\$ -	\$ 5,859	\$ 5,859
On-Peak Demand	690.80	\$ 11.11	\$ -	\$ 11.11	\$ 7,675	\$ -	\$ 7,675
NCP kW	5,713.20	\$ -	\$ 3.22	\$ 3.22	\$ -	\$ 18,397	\$ 18,397
Energy Charge per kWh	564,880	\$ 0.045405	\$ 0.006370	\$ 0.051775	\$ 25,648	\$ 3,598	\$ 29,247
Base Revenue					\$ 33,323	\$ 27,854	\$ 61,177
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 33,323	\$ 27,854	\$ 61,177
Large C&I TOU (Proposed to be available to all Large C&I customers)							
Service Charge (12 Month Sum)		\$ -	\$ 189.00	\$ 189.00	N/A	N/A	N/A
On-Peak Demand		\$ 23.00	\$ -	\$ 23.00	N/A	N/A	N/A
NCP kW		\$ -	\$ 3.22	\$ 3.22	N/A	N/A	N/A
Energy Charge per kWh		\$ 0.045405	\$ 0.006370	\$ 0.051775	N/A	N/A	N/A
Base Revenue					N/A	N/A	N/A
PPCA Revenue					N/A	N/A	N/A
Total Revenue					N/A	N/A	N/A
Large C&I GOV							
Service Charge (12 Month Sum)	362	\$ -	\$ 175.00	\$ 175.00	\$ -	\$ 63,350	\$ 63,350
NCP Demand	64,343.36	\$ 7.81	\$ 3.22	\$ 11.03	\$ 502,522	\$ 207,186	\$ 709,707
Energy Charge per kWh	17,180,160	\$ 0.063682	\$ 0.006370	\$ 0.070052	\$ 1,094,067	\$ 109,438	\$ 1,203,505
Base Revenue					\$ 1,596,589	\$ 379,973	\$ 1,976,562
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 1,596,589	\$ 379,973	\$ 1,976,562
Billed at Subtransmission Delivery Level							
Service Charge (12 Month Sum)	12	\$ -	\$ 175.00	\$ 175.00	\$ -	\$ 2,100	\$ 2,100
NCP kW	53,106.00	\$ 7.81	\$ 3.22	\$ 11.03	\$ 414,758	\$ 171,001	\$ 585,759
Energy Charge per kWh	30,204,000	\$ 0.063682	\$ 0.006370	\$ 0.070052	\$ 1,923,451	\$ 192,399	\$ 2,115,851
Subtransmission Discount on Demand & Energy		\$ -7.50%	\$ -7.50%	\$ -7.50%	\$ (175,366)	\$ (27,413)	\$ (202,778)
Base Revenue					\$ 2,162,843	\$ 338,088	\$ 2,500,932
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 2,162,843	\$ 338,088	\$ 2,500,932

Follows Structure of Mohave's Supplemental Schedule N-1.0

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

108	Billing Units	Proposed Rate		Proposed Revenue	
		Pur Pwr	Dist Wires	Total	Total
4.	LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)				
	LP Substation				
	Service Charge (12 Month Sum)				
	NCP KW	67,500.00	\$ 7.81	\$ 527,175	\$ 4,200
	Energy Charge per kWh	38,802,000	\$ 0.006370	\$ 2,470,989	\$ 217,350
	Substation Discount on Demand & Energy			\$ (149,908)	\$ 2,718,158
	Base Revenue			\$ (23,436)	\$ (173,344)
	PPCA Revenue			\$ 2,848,256	\$ 3,293,539
	Total Revenue			\$ 445,283	\$ 3,293,539
				\$ 445,283	\$ 3,293,539
	Base Revenue	171,559,418		\$ 2,573,658	\$ 16,221,770
	PPCA Revenue			\$ -	\$ -
	Total Revenue			\$ 2,573,658	\$ 16,221,770
5.	LIGHTING SERVICE				
	175 W MVL	6,039	6.13	\$ 37,019	\$ 5,918
	100 W HPS	2,594	3.07	\$ 7,964	\$ 13,982
	175 W MVL CO	320	6.07	\$ 1,942	\$ 183
	100 W HPS CO	3,644	3.07	\$ 11,187	\$ 8,527
	250 W HPS	1,211	7.81	\$ 9,458	\$ 7,436
	Base Revenue	13,808		\$ 67,570	\$ 36,026
	PPCA Revenue			\$ -	\$ -
	Total Revenue			\$ 67,570	\$ 36,026
	kWh	1,100,103			
6.	RESALE REVENUE				
	Base Revenue			\$ 3,222,980	\$ 475,687
	PPCA Revenue			\$ -	\$ -
	Total Revenue	46,862,961		\$ 3,222,980	\$ 475,687
7.	TOTAL REVENUE				
	Base Revenue	702,606,696		\$ 17,054,017	\$ 78,262,361
	PPCA Revenue			\$ -	\$ -
	Other Revenue			\$ 867,282	\$ 867,282
	Total			\$ 17,921,299	\$ 79,129,643

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (Updated to 2010)

RESIDENTIAL COMPARISON OF EXISTING MOHAVE PROPOSED AND STAFF SURREBUTTAL RATES - 2010 USAGE

	Existing Rate	Mohave Proposed Rate	% Change	Staff Surrebittal Rate	% Change
Service Charge	\$9.50	\$16.50	73.7%	\$ 13.50	42.1%
Energy Charge, per kWh					
First 400	\$0.083190	\$0.096373	15.8%	\$0.093351	12.2%
Next 600	\$0.083190	\$0.106373	27.9%	\$0.108351	30.2%
Over 1,000	\$0.083190	\$0.116373	39.9%	\$0.123351	48.3%
PPCA Factor	\$0.023685	(\$0.001850)	-107.8%	\$0.000000	-100.0%
Total Energy Charge plus PPCA					
First 400	\$0.106875	\$0.094523	-11.6%	\$0.093351	-12.7%
Next 600	\$0.106875	\$0.104523	-2.2%	\$0.108351	1.4%
Over 1,000	\$0.106875	\$0.114523	7.2%	\$0.123351	15.4%

kWh Usage	Monthly Cust ¹	Existing Rate	Mohave Proposed Rate	Mohave Change fr. Existing	Mohave % Change fr. Existing	Staff Proposed Rate	Staff Change fr. Existing	Staff % Change fr. Existing
0	1,009	\$9.50	\$16.50	\$7.00	73.68%	\$13.50	\$4.00	42.11%
100	2,913	\$20.19	\$25.95	\$5.76	28.56%	\$22.84	\$2.65	13.12%
200	2,687	\$30.88	\$35.40	\$4.53	14.67%	\$32.17	\$1.30	4.19%
400	5,213	\$52.25	\$54.31	\$2.06	3.94%	\$50.84	(\$1.41)	-2.70%
800	9,166	\$95.00	\$96.12	\$1.12	1.18%	\$94.18	(\$0.82)	-0.86%
1,000	3,212	\$116.38	\$117.02	\$0.65	0.56%	\$115.85	(\$0.52)	-0.45%
2,000	7,881	\$223.25	\$231.55	\$8.30	3.72%	\$239.20	\$15.95	7.15%
3,000	2,466	\$330.13	\$346.07	\$15.94	4.83%	\$362.55	\$32.43	9.82%
5,000	738	\$543.88	\$575.12	\$31.24	5.74%	\$609.26	\$65.38	12.02%
8,000	54	\$864.50	\$918.68	\$54.18	6.27%	\$979.31	\$114.81	13.28%
Over	4							
860 Average		\$101.41	\$102.39	\$0.98	0.96%	\$100.68	(\$0.73)	-0.72%
637 Median		\$77.58	\$79.08	\$1.50	1.94%	\$76.52	(\$1.06)	-1.37%

Note 1 - Customers with usage from the previous block to this block

1 **BEFORE THE ARIZONA CORPORATION COMMISSION**

Arizona Corporation Commission

2 COMMISSIONERS

DOCKETED

3 JEFF HATCH-MILLER, Chairman
4 WILLIAM A. MUNDELL
5 MARC SPITZER
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AUG 17 2005

DOCKETED BY

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8 IN THE MATTER OF THE APPLICATION OF
9 ARIZONA ELECTRIC POWER COOPERATIVE,
10 INC, FOR A RATE INCREASE.

DOCKET NO. E-01773A-04-0528

11 IN THE MATTER OF THE APPLICATION OF
12 SOUTHWEST TRANSMISSION COOPERATIVE,
13 INC., FOR A RATE INCREASE.

DOCKET NO. E-04100A-04-0527

DECISION NO. 68071

OPINION AND ORDER

14 DATE OF HEARING:

April 14, 2005

15 PLACE OF HEARING:

Tucson, Arizona

16 ADMINISTRATIVE LAW JUDGE:

Jane L. Rodda

17 APPEARANCES:

Michael M. Grant, Gallagher & Kennedy,
PA, on behalf of Arizona Electric Power
Cooperative, Inc.;

Michael A. Curtis, Curtis, Goodwin,
Sullivan, Udall & Schwab, PLC, on
behalf of Mohave Electric Cooperative,
Inc.;

Christopher Hitchcock, Law Offices of
Christopher Hitchcock, for Sulphur
Springs Valley Electric Cooperative;

John Leonetti, in propria persona; and

Timothy Sabo and Diane Targovnik,
Commission Legal Division for the
Utilities Division.

* * * * *

24 Having considered the entire record herein and being fully advised in the premises, the
25 Commission finds, concludes, and orders that:

FINDINGS OF FACT

27 1. On July 23, 2004, Arizona Electric Power Cooperative, Inc. ("AEPCO" or
28

1 "Cooperative") filed an Application for General Rate Increase.¹

2 2. AEPCO is a nonprofit member owned cooperative that provides power generation
3 service to six Class A member distribution cooperatives. The distribution cooperatives provide
4 electricity at retail to their member owners. Prior to 2001, AEPCO provided both generation and
5 transmission service to its members. In Decision No. 63868 (July 25, 2001) the Commission
6 approved the reorganization of AEPCO into three separate and affiliated cooperatives: AEPCO
7 provides generation; Southwest Transmission Cooperative Inc. ("SWTC") provides transmission; and
8 Sierra Southwest Cooperative ("Sierra") provides wholesale marketing and support services to
9 AEPCO and SWTC.

10 3. AEPCO's Class A members are Anza Electric Cooperative, Inc. ("Anza"), located
11 entirely in California; Duncan Valley Electric Cooperative, Inc. ("DVEC"), located partially in New
12 Mexico; Graham County Electric Cooperative, Inc. ("GCEC"); Sulphur Springs Valley Electric
13 Cooperative, Inc. ("Sulphur Springs"); Trico Electric Cooperative, Inc. ("Trico"); and Mohave
14 Electric Cooperative, Inc. ("Mohave"). Currently, Mohave is a partial requirements member, and
15 Sulphur Springs is in the process of converting to a partial requirements member.² Partial
16 requirements members contract with AEPCO to furnish only a portion of its retail electricity
17 requirements and must plan for and secure the balance of its generation needs from either AEPCO or
18 another generator. All other Class A members are full requirements members which means they
19 obtain all of their generation service from AEPCO.

20 4. On August 27, 2004, Commission Utilities Division Staff ("Staff") notified AEPCO
21 that its Application met the sufficiency requirements of A.A.C. R14-2-103. Staff classified AEPCO a
22 Class A utility.

23 5. Counsel for AEPCO and Staff requested a Procedural Conference prior to the Hearing
24 Division issuing its Procedural Order setting the matter for hearing. Pursuant to Procedural Order
25 dated September 3, 2004, a Procedural Conference was held on September 9, 2004. AEPCO

26
27 ¹ On the same date, its affiliate, Southwest Transmission Cooperative, Inc. ("SWTC") filed a rate application (Docket No.
E-04100A-04-0527).

28 ² For purposes of the application, Sulphur Springs is treated as a full requirements customers because it was during the
test year and it is unknown when the necessary approvals will be obtained to convert to a partial requirements member.

1 requested an expedited schedule for filing testimony and conducting the hearing based on the
2 Commission's prior indication that it would be flexible when considering rate applications from
3 cooperatives, and upon the allegation that AEPCO was losing money and would be in technical
4 default of financial ratios set by its lenders. Staff opposed the expedited schedule because the issues
5 in this case are potentially complex and Staff wanted to be sure that all issues received adequate
6 analysis. Staff claimed it needed the full 180 days allowed under Commission Rules for Staff to file
7 testimony in a Class A utility rate case. In addition, Staff requested that the AEPCO and SWTC rate
8 applications be consolidated on the grounds that they are affiliates and there will be issues and
9 witnesses in common which favor consolidation. Staff feared that if the records were not
10 consolidated, one or the other might be incomplete. AEPCO and SWTC opposed consolidation,
11 believing that it might lead to confusion.

12 6. By Procedural Order dated September 15, 2004, the Commission denied the request
13 for an expedited schedule. The applications are the first rate cases for AEPCO and SWTC since the
14 restructuring, and the Commission found that the need for a thorough analysis outweighed the request
15 for expedited treatment. In addition, because the applications involve affiliates and their rate cases
16 will involve several inter-related issues, the Commission consolidated the matters for hearing.

17 7. The September 15, 2004, Procedural Order established deadlines for filing testimony
18 and set the hearing to commence April 14, 2005, at the Commission's offices in Tucson, Arizona.

19 8. On January 11, 2005, AEPCO filed a Notice of Filing that indicated it had mailed
20 notice of the hearing to its members and customers and had caused the notice of the hearing to be
21 published in newspapers and in the newsletters of its member distribution cooperatives, as required
22 by the September 15, 2004, Procedural Order.

23 9. Intervention was granted to Mohave on November 2, 2004; to Sulphur Springs on
24 January 25, 2005; and to John T. Leonetti, a resident in Trico's service territory, on March 10, 2005.

25 10. With its Application, AEPCO filed the direct testimony of Dirk Minson, AEPCO's
26 Chief Financial Officer; Gary Pierson, Manager of Financial Services for Sierra and who provides
27 treasury, cash management, risk management and rate design/implementation functions for AEPCO;
28 Stephen Daniel, the Executive Vice President of GDS Associations, a consultant for AEPCO who

1 testified about cost allocation methodology; and William Edwards, an economist and Vice President
2 of Regulatory Affairs for the National Rural Utilities Cooperative Finance Corporation ("CFC").
3 Pursuant to the September 15, 2004 Procedural Order, Staff filed the direct testimony of Crystal
4 Brown, Alejandro Ramirez, Barbara Keene and Jerry Smith on February 23, 2005. On March 16,
5 2005, AEPCO filed the rebuttal testimony of Messrs. Minson and Pierson. On April 4, 2005, Staff
6 filed the surrebuttal testimony of Ms. Brown, Ms. Keene and Mr. Ramirez.

7 11. The hearing convened as scheduled on April 14, 2005, before a duly authorized
8 Administrative Law Judge.

9 12. AEPCO, Staff, Mohave and Mr. Leonetti filed Closing Briefs.

10 13. In the course of this proceeding the Commission received at least 23 letters and phone
11 calls from customers of the distribution cooperatives in opposition to the proposed increase.

12 14. In the test year ended December 31, 2003 ("Test Year"), according to Staff, AEPCO
13 had Adjusted Operating Revenue of \$138,919,725, resulting in Adjusted Operating Income of
14 \$10,425,443. AEPCO had a margin loss of \$711,329, and its Debt Service Coverage Ratio ("DSC")
15 had slipped to 0.70, below the Rural Utilities Service ("RUS") mortgage minimum requirement of
16 1.0. AEPCO suffered another operating loss in 2004, and is no longer in compliance under the terms
17 of its mortgage or pursuant to the rules of the RUS, primarily 7 CFR 1710.114. At the end of the
18 Test Year, AEPCO's equity comprised 4.8 percent of its capitalization, but continued losses have
19 caused its equity to drop to approximately 3 percent.

20 15. AEPCO blamed the poor operating results in the Test Year and subsequently on higher
21 delivered coal and natural gas costs, increased maintenance costs associated with an aging generation
22 plant at the Apache Generating Station, and necessary capital additions
23 to meet load growth on the Class A members' distribution systems.

24 16. AEPCO's current rates for Class A members were authorized in Decision No. 58405
25 (September 3, 1993) and Decision No. 62758 (July 22, 2000). Decision No. 58405 authorized a
26 Times Interest Earned Ratio ("TIER") of 1.05 and a DSC of 1.0 to provide a 12.96 percent rate of
27 return on rate base. Decision No. 62758 authorized the Cooperative's competitive transition charge.

28 17. In its application, AEPCO sought approval for annual revenues of \$146,061,466, an

1 increase of \$7,141,741, or 5.14 percent over Staff's adjusted Test Year revenues. According to the
2 Cooperative, its request would have produced an operating margin of \$16,422,692, a net margin of
3 \$3,922,406, TIER of 1.29 and DSC of 1.05. The Cooperative calculates TIER and DSC using the
4 same formula as the RUS, which includes non-operating revenue. In its application, the Cooperative
5 had claimed an adjusted rate base of \$222,147,011, and its requested increase would have resulted in
6 a rate of return of 7.39 percent.

7 18. In surrebuttal, Staff recommended a revenue requirement of \$148,397,723, an increase
8 of \$9,477,998, or 6.82 percent over Test Year adjusted revenues. Staff's recommended revenue level
9 would yield an operating margin before interest of \$19,903,441, a 10.5 percent rate of return on an
10 original cost rate base of \$189,637,810, and provide a 1.50 TIER and a DSC of 0.99. The formula
11 that Staff utilizes to calculate DSC does not include non-operating income and results in a more
12 conservative calculation.

13 19. After reviewing Staff's direct and surrebuttal testimony, AEPCO revised its revenue
14 request in its rejoinder testimony, and even further by the date of the hearing. As its final position,
15 AEPCO sought a total revenue requirement of \$152,279,043. In addition AEPCO agreed to all of
16 Staff's recommendations on rate base. Staff and AEPCO agreed that because of its cooperative
17 structure, cash flow and debt coverage ratios were more relevant to determining AEPCO's required
18 revenue requirement than the rate of return on rate base. Thus, at the hearing, Staff and AEPCO
19 agreed that to generate sufficient cash flow for debt service, to meet its capital investment needs and
20 to increase its equity, AEPCO should be authorized a revenue increase of \$13,359,318, or 9.6 percent
21 for a total revenue requirement of \$152,279,043.

22 20. AEPCO proposed that in order to come back into compliance with its mortgage
23 requirements and to minimize the impact of the revenue increase, \$10,751,925 of the increase should
24 become effective immediately, and that the remaining \$2,607,393 of the increase should be phased in
25 over the following two years. The first phase of the rate increase would yield a TIER of 1.59 and a
26 DSC of 1.04 (utilizing Staff's calculation methodology), and would result in a rate of return of 11.17
27 percent on adjusted original cost rate base ("OCRB").

28 21. In the second phase, which would become effective after one year, or September 1,

1 2006, revenues would increase an additional \$1,295,119. Phase Two would result in total revenues
2 of \$150,966,969, and yield a TIER of 1.69, a DSC of 1.08, and a rate of return on OCRB of 11.86
3 percent.

4 22. Phase Three would result in an additional increase of \$1,312,274, and would go into
5 effect on September 1, 2007. This phase would yield total revenue of \$152,279,043, resulting in a
6 TIER of 1.79, DSC of 1.13 and rate of return of 12.54 percent on OCRB.

7 23. AEPCO estimates that on the retail level, the Phase One increase would result in an
8 approximate \$3.70 monthly bill increase for an average residential customer of its member
9 distribution cooperatives who uses 750 kWh. AEPCO estimates the combined effect of the deferred
10 increases in 2006 and 2007 would produce another approximate \$0.90 monthly retail increase spread
11 over the next two years.

12 24. AEPCO designed Phases Two and Three to generate additional revenue to allow the
13 Cooperative to maintain its equity balances as additional principal payments become due in 2006 and
14 2007. (TR at 151-53).

15 25. AEPCO's Board of Directors did not have an opportunity to approve the proposed step
16 increases prior to the hearing. AEPCO submitted a resolution of the Board approving the step
17 increase proposal as a late-filed exhibit. The resolution contains the following proviso:

18 However, the AEPCO Board of Directors requests that the effective rate
19 order provide that the 1.5 percent increases will only be enacted after a
20 submittal by AEPCO of relevant financial information to the ACC prior
21 to the scheduled increases, and only if this information demonstrates that
22 the rate increases are necessary to achieve a Debt Service Coverage Ratio
23 of 1.0 AEPCO staff is instructed to submit all such financial
24 information to the Board for approval prior to its submission to the ACC.

25 26. Commission Staff does not support the proviso adopted by the AEPCO Board because
26 the term "relevant financial information" is undefined and it seems to suggest that future orders of the
27 Commission would be necessary to "enact" the step increases. In addition, Staff notes that the
28 AEPCO Board might be able to block any step increases simply by failing to forward the
information. More fundamentally, Staff argues, the conditional approach adopted by AEPCO's
Board appears to be based on the notion that a DSC of 1.0 is reasonable and prudent, and perhaps

1 excessive, while it is Staff's view that a DSC of 1.0 is the absolute minimum, and leaves no room for
2 unexpected events. Staff argues the proviso makes it nearly impossible to build equity. Staff
3 recommends that the Commission approve the step increases without condition or need for future
4 order of the Commission.

5 27. Intervenor Leonetti opposed any rate increase for AEPCO at this time. Mr. Leonetti
6 believed that although the target DSC of 0.99 and TIER of 1.5 are reasonable in light of testimony
7 indicating that the RUS and CFC require a minimum DSC of 1.0 and minimum TIER of 1.05, he
8 argued that neither AEPCO nor Staff demonstrated that the rates they agreed to are reasonable. In
9 addition to the lenders' target financial ratios, Mr. Leonetti argues that the Commission should
10 consider the effect of the proposed rate increase on ratepayers (Leonetti Brief at 2).

11 28. Mohave, one of AEPCO's Class A Members, and represented on AEPCO's Board of
12 Directors, supports the step increase, as proposed by AEPCO, and as conditioned by the AEPCO
13 Board of Directors. Mohave adds that in developing their revenue recommendations, Staff did not
14 consider basic differences between the all-requirements and partial-requirements customers of
15 AEPCO.

16 29. We agree with Staff that AEPCO's proposed conditions for the step increases appear
17 unnecessarily complicated and could delay the implementation of the rates we find necessary to
18 restore AEPCO's financial health. The conditions were proposed for the first time after the hearing
19 and neither Staff, the non-member intervenor, nor the Commission could cross examine the
20 proponents concerning how the conditioned increases would be enacted. A total revenue level of
21 \$152,279,043, as was proposed at the hearing, is fair and reasonable and fully supported by the
22 evidence. The revenue increase is designed not only to meet lenders' minimum financial ratio
23 requirements, but to permit the Cooperative to build much needed equity. If events demonstrate that
24 AEPCO is able to build equity consistent with the goals established later in this Order, AEPCO may
25 consider filing an application to modify rates. AEPCO has stated it would be filing another rate
26 application in three to five years in any event. The future conversion of Sulphur Springs to a partial
27 requirements member may also affect the timing of the next rate case. There is no evidence that the
28 rates agreed to by Staff and AEPCO are unfair to any member or end user. We adopt the phased in

1 approach in an effort to minimize the immediate impact on rate payers.

2 30. AEPCO and Staff agreed on the rates to be implemented to achieve the revenue
3 requirement. The schedule of proposed rates is attached hereto as Exhibit A. We find that a revenue
4 requirement of \$152,279,043, is fair and reasonable, and that it is in the public interest that the
5 revenue increase be phased in over two years as set forth in Exhibit A.

6 31. Mohave recommends that AEPCO file a rate case six months after Sulphur Springs
7 has completed a full year as a partial requirements member.

8 32. Mohave's recommendation that AEPCO file a rate application after a full year of
9 operating data after Sulphur Springs has become a partial requirements member is well-founded.
10 Sulphur Springs is one of AEPCO's largest members and its change of status may have significant
11 impact on AEPCO's revenues. Thus, we will adopt Mohave's recommendation, and require AEPCO
12 to file a rate case six months after Sulphur Springs has completed a full calendar year as a partial
13 requirement member. By specifying "calendar year" AEPCO can match its Test year with its fiscal
14 year.

15 33. Staff and AEPCO agree that an adjusted original cost rate base of \$189,637,810 is fair
16 and reasonable. No party objected to Staff's rate base adjustments. Based on the evidence, we
17 concur that Staff's adjustments to rate base are reasonable and should be adopted. AEPCO waived a
18 reconstruction cost new rate base and thus, its original cost rate base is the equivalent of its fair value
19 rate base.

20 34. Staff and AEPCO also agree that a Fuel and Purchased Power Cost Adjustor
21 ("FPPCA") should be established for AEPCO. Staff explained that the FPPA would track changes in
22 the cost of fuel for AEPCO's generating units and power purchased from others and would be
23 calculated by comparing the rolling 12-month average of actual fuel and purchased power costs to the
24 base cost established in this rate case. The rate would be applied to the member bills as a kilowatt-
25 hour charge. Whether AEPCO's distribution cooperative members could pass additional FPPCA
26 charges on to end-users would depend on whether they had purchased power adjuster clauses in their
27 tariffs. Under Staff's proposal, the adjustor rate, initially set at zero, would be reset semi-annually on
28 October 1, 2006, and April 1, 2007, and thereafter on October 1 and April 1 of each subsequent year.

1 AEP would submit a publicly available report, with a revised tariff, that shows the calculation of the
2 new rate on September 1, 2006 and March 1, 2007, and thereafter on September 1 and March 1 of
3 each subsequent year. The adjustor rate would become effective with billings for October and April
4 unless suspended by the Commission. AEPCO accepted all of Staff's recommendations on clause
5 administration and reporting as set forth in Ms. Keene's direct testimony.

6 35. With respect to the FPPCA, Staff further recommends:

- 7 a. The FPPCA will expire in five years unless extended by the
8 Commission;
- 9 b. The Commission or Staff will have the right to review the prudence of
10 fuel and power purchases at any time;
- 11 c. The Commission or Staff will have the right to review any calculations
12 associated with the FPPCA at any time;
- 13 d. Any costs flowed through the FPPCA are subject to refund if the
14 Commission determines that the costs are imprudent;
- 15 e. AEPCO will file monthly reports with Staff's Compliance Section
16 detailing all calculations relating to the FPPCA and containing the nine
17 minimum requirements specified in Ms. Keene's Direct Testimony (Ex.
18 S-7);
- 19 f. AEPCO will file additional monthly reports regarding its generating
20 units, power purchases, and fuel purchases. The report will comply
21 with the minimum requirements specified in Ms. Keene's Direct
22 Testimony.

23 36. AEPCO's fuel and purchased power expenses amounted to almost one-half of
24 AEPCO's total expenses for the adjusted 2003 test year. AEPCO asserted that the volatility was a
25 primary reason AEPCO suffered a margin loss in the Test Year. We recognize that the FPPCA is
26 intended to allow timely recovery of increases in fuel and purchased power costs, or to allow the
27 refund of any decreases, without the time and expense of a full rate proceeding. We also note that no
28 party objected to Staff's recommendations for the FPPCA. However, we are concerned with the

1 possibility that AEPCO's recovery of fuel and purchased power costs under Staff's proposed FPPCA
2 may nonetheless be outpaced by the rate of future fuel and purchased power cost increases.
3 Therefore, we will approve the FPPCA on the terms agreed to by the parties, but in so doing, we will
4 attach an additional condition allowing AEPCO to request the Commission to review the efficacy of
5 the FPPCA when AEPCO submits any semi-annual FPPCA report as required elsewhere in this
6 Decision.

7 37. Staff agrees with AEPCO that a separate base cost of power be established for full-
8 requirements and partial-requirements customers. Staff recommends that the base cost of power for
9 full-requirements customers should be set at \$0.01687 per kWh and that the base cost of power for
10 partial-requirements customers should be set at \$0.01603 per kWh. AEPCO agreed with Staff's
11 recommended rates.

12 38. As part of this proceeding AEPCO requested the approval of revised depreciation
13 rates. The lower depreciation rates are based upon a study and would lower costs in the Test Year by
14 slightly more than \$1.47 million. Staff agreed that the revised depreciation rates, as shown on
15 Exhibit DCM-1 of Dirk Minson's Direct Testimony (Ex. AEPCO-1) should be approved.

16 39. Staff recommends that the Commission approve a Demand Side Management (DSM)
17 adjustor.

18 40. AEPCO does not agree that as a wholesale generator, AEPCO should engage in DSM
19 programs. The parties have agreed to reserve the issue of the specific DSM requirements for AEPCO
20 to the pending DSM rulemaking docket (Docket No. RE-00000C-05-0230). (Staff Brief at 6)
21 AEPCO agrees with Staff that the Commission should approve a DSM adjustor mechanism.

22 41. Mohave recommends that the Commission provide that in any DSM requirement, that
23 each distribution cooperative be responsible for its own program and not be subject to AEPCO's
24 direction.

25 42. We find that it is reasonable to determine AEPCO's obligations with respect to
26 specific DSM programs in the DSM rulemaking docket, but that in anticipation of the adoption of
27 those rules and the potential that AEPCO may engage in DSM programs, approving a DSM adjustor
28 mechanism at this time is reasonable.

1 43. AEPCO's equity ratio is far below sample generation and transmission cooperatives
2 which have a national median equity level of 13 percent. (Ex AEPCO 6 – page 10). Staff's witness
3 used a comparison group of cooperatives that are rated by Standard and Poors that had an average
4 equity of 19 percent. (Ex S-11 and S-12)

5 44. Staff recommends that AEPCO file a capital improvement plan by March 31, 2006.
6 Staff further recommends that the Commission set an equity goal for AEPCO of 30 percent. Staff
7 based its recommended goal on: (1) the goals set in prior orders concerning AEPCO (Decision No.
8 64227); (2) AEPCO's need to achieve greater financial flexibility; and (3) an article by Fitch Ratings
9 which states that an equity-to-capitalization ratio between 25 to 30 percent is adequate for a
10 generation and transmission cooperative. (Ex S-12 at 6) Staff notes that in Decision No. 67748
11 (April 11, 2005), the Commission recently approved the same 30 percent equity goal for Graham
12 County Utilities.³ Staff believes the 30 percent equity goal would be consistent with RUS regulations
13 which limit patronage refunds until 30 percent equity is achieved.

14 45. Staff further recommends that the Commission limit AEPCO from making patronage
15 refunds. Specifically, Staff recommends that AEPCO should not be permitted to make any patronage
16 refunds while its equity level remains below 20 percent of total capitalization. If AEPCO's equity
17 level is between 20 percent and 30 percent, Staff recommends that patronage refunds be limited to 25
18 percent of net earnings, which Staff states parallels the RUS regulations.

19 46. Staff also recommends that to ensure AEPCO makes progress in building equity, that
20 it should be required to file a rate case no later than 3 to 5 years from the date of this Decision.

21 47. AEPCO does not oppose filing an equity improvement plan or the requirement it file a
22 rate case not later than five years. AEPCO opposes, however, the concept that 30 percent equity is an
23 appropriate goal for the Commission to adopt. AEPCO cites evidence that the average and median
24 equity levels for generation and transmission cooperatives nationwide is much lower. AEPCO also
25 argues that there are many factors, besides equity, which impact the financial strength of AEPCO.
26 According to AEPCO, Fitch Ratings looked at some 12 different factors in assigning a rating to
27

28 ³ Graham County Utilities, Inc., ("GCU") is a cooperative owned by Graham County Electric Cooperative, Inc. to provide natural gas and water service. Graham County Electric Cooperative is the Class A member of AEPCO.

1 Golden Spread Electric Cooperative (the subject of the article relied upon by Staff) including the
2 strength of its requirements contracts, management quality, adequate liquidity, overall financial
3 profile, DSC and TIER, as well as equity. AEPCO argues that neither it, nor the Commission, would
4 want to be in the difficult position where unnecessarily high rate increases are driven by an equity
5 target that is inflexible and arbitrarily set.

6 48. Mohave recommends that the Commission require AEPCO to file an Equity
7 Improvement Analysis by March 31, 2006, which should include: 1) an analysis of the benefits, if
8 any, that Partial Requirement Members ("PRMs") obtain by improving the equity position of
9 AEPCO; 2) an analysis of the benefits All Requirements Members ("ARMs") obtain by improving
10 the equity position and of the optimum equity level to obtain such benefits; 3) an analysis of methods
11 other than rate increases for increasing equity; and 4) a consideration of possible methods to permit
12 future borrowing to meet load growth of ARMs to be based upon the equity of those ARMs that
13 benefit from the borrowing.

14 49. AEPCO provides wholesale service to six distribution cooperatives. Mohave states
15 that typically, a generation cooperative will plan to serve the total power supply requirements for all
16 of its members, however, AEPCO does not have the same power supply obligation for each of the six
17 members. Two of the six members—Mohave and Sulphur Springs—have elected to change from all
18 requirements members to partial requirements members. Mohave states that these two members
19 reflect approximately 65 percent of the Test Year power supply requirements billing units. According
20 to Mohave, AEPCO does not have to plan for serving, nor does it have the responsibility to serve, the
21 load growth of the partial requirements members in excess of the allocated AEPCO resources.
22 Mohave asserts AEPCO has no future capital requirements associated with new resources to serve
23 approximately 65 percent of the total member load. Mohave argues that Staff's recommended
24 revenue requirement is based on the need to maintain financial stability to finance future plant
25 additions and replacements⁴, and Mohave believes there is a question of the fairness of a requirement
26 that a customer who will not cause, and is not allowed to participate in, the future event to have

27
28 ⁴ Mohave asserts that one of Staff's justifications for the proposed increase in equity is to make certain that AEPCO has access to capital markets to provide debt capital to build future power supply resources.

1 revenue responsibility for that event. Mohave argues that prior to allowing the allocation of any
2 revenue responsibility associated with a future event to a partial requirements member, there should
3 be findings as to whether or not the proposed assets will be used and useful in serving the partial
4 requirements member. Mohave asserts the record in this proceeding is devoid of data relating to
5 future capital needs required to serve a partial requirements member.

6 50. Mohave asserts that the equity level recommended by Staff is excessive, as the lender
7 has indicated that it is not necessary to achieve the Staff recommendations in order to obtain
8 financing. In addition, Mohave asserts that Staff did not analyze the impact on the ratepayer in
9 developing its equity recommendations.

10 51. In Decision No. 64227 (November 29, 2001) the Commission approved AEPCO's
11 financing request and ordered AEPCO to file a capital plan by December 31, 2002. In that docket,
12 Staff recommended that AEPCO increase its equity to 10 percent by December 31, 2006, to 15
13 percent by December 31, 2010, and to 30 percent by December 31, 2015.

14 52. AEPCO filed the Capital Plan required by Decision No. 64227 on December 23, 2002,
15 and provided a copy as a late-filed exhibit in this docket. AEPCO's December 2002 Capital Plan
16 indicates that equity levels were projected to reach 12 percent in 2006, 27 percent in 2010 and 31
17 percent in 2011. As is evident from its current rate application, AEPCO's assumptions that formed the
18 basis of its December 2002 Capital Plan did not materialize.

19 53. The evidence presented in this proceeding indicates that AEPCO must improve its
20 equity position. It is currently not in compliance with its lenders' equity requirements. The evidence
21 is inconclusive, however, to make a finding at this time that a 30 percent capital requirement is an
22 appropriate goal for a generation cooperative such as AEPCO. Mr. Edwards testified that the median
23 equity ratio for a generation and transmission cooperative is 13.22 percent in 2002, the most recent
24 available year of data. Furthermore, the RUS and CFC do not discriminate on the price of loans
25 based on equity levels. (TR at 63). There is some evidence that adopting and enforcing an equity
26 goal of 30 percent may place undue upward pressure on rates and that a 30 percent equity level is not
27 required to protect AEPCO's ability to access the financial markets. On the other hand, just because
28 national averages for generation and transmission cooperatives are below 20 percent, does not mean

1 that we should not strive for equity greater than that to give the cooperative a cushion to weather
2 economic setbacks. AEPCO did not present sufficient evidence to allow us to determine that a
3 specific goal less than 30 percent is reasonable. In his rebuttal testimony, Mr. Minson testified that
4 the revenues that the Cooperative was recommending at that time (somewhat less than their final
5 position) would allow AEPCO to reach 30 percent equity in about eight years. (Ex A-2 at 8). If Mr.
6 Minson is correct, then AEPCO should be in compliance with Staff's recommendations set forth in
7 Decision No. 64227. We believe that AEPCO should update its December 2002 Capital
8 Improvement Plan, with updated assumptions and provide an analysis of the rates that would be
9 required to achieve an equity level of 30 percent, within ten years, or 2015. We do not adopt a
10 requirement now, nor does Decision No. 64227 specifically require, that AEPCO achieve any
11 specific equity goal. We do adopt the rates herein with the expectation that AEPCO will be able to
12 build much needed equity. Because we are requiring AEPCO to file another rate case in no more
13 than five years, in any case, adopting an ultimate goal of 30 percent at this time is not necessary.

14 54. Whereas Mohave raises interesting issues regarding the differences between partial
15 and full requirements members, it makes its position known for the first time in its Closing Brief.
16 Mohave did not file testimony in this case. Mohave and Sulphur Springs are two of AEPCO's largest
17 members. We believe Mohave's suggestion that the capital improvement plan that AEPCO will file
18 in 2006 should specifically address its obligations to partial requirements members is well-founded,
19 and direct AEPCO to include such analysis in its 2006 updated report.

20 55. AEPCO did not file jurisdictionally separated information for Anza in this rate case,
21 nor has it ever filed such information in any prior rate case.

22 56. Staff recommends that in its next rate case, AEPCO prepare jurisdictionally separated
23 schedules for Anza.

24 57. Commission rule R14-2-103(B)(4) provides in relevant part:

25 Separation of nonjurisdictional properties, revenues and expenses
26 associated with the rendition of utility service not subject to the
27 jurisdiction of the Commission must be identified and properly separated
28 in a recognized manner when appropriate. In addition, all nonutility
properties, revenues and expenses shall likewise be segregated.

58. Staff argues that jurisdictional separation is an important tool that Staff uses to ensure

1 that rates are fair and cost-based. Staff states that Duncan Valley Electric Cooperative Inc., Garkane
2 Power Association, Inc. and Columbus Electric Cooperative, all cooperatives within the
3 Commission's jurisdiction with multi-state operations, file jurisdictionally separated information.
4 Staff does not believe arguments that a separation study would be too costly in comparison with the
5 expected benefits justify a waiver of the requirement. Staff also asserts that once the first study is
6 prepared, future separations will be substantially easier.

7 59. AEPCO opposed the recommendation to jurisdictionally separate its operations
8 associated with Anza. According to AEPCO, Anza's load represents only 1.5 percent of AEPCO's
9 total energy sales in 2003. AEPCO estimates the cost of a separation study would be \$40,000 to
10 \$60,000 and the cost of service differences for Anza, if any, would not justify the expense or the
11 effort to evaluate its findings. Under these circumstances, AEPCO argues that to prepare such study
12 would be an "undue burden," which is one of the grounds for waiver under A.A.C. R14-2-103.B.6.

13 60. Given the circumstances of this case, we will not require AEPCO to prepare and file
14 jurisdictionally separated schedules for Anza. However, consistent with our findings in Decision No.
15 67220 (August 24, 2004) AEPCO shall submit with its next rate case cost information that (1)
16 separates the costs to serve Class A members from the costs to serve other classes; (2) categorizes the
17 costs by demand, energy and customer-related; and (3) breaks down the costs for ancillary services
18 by costs component in accordance with FERC definitions, with firm and variable costs separated.

19 CONCLUSIONS OF LAW

20 1. AEPCO is a public service corporation pursuant to Article XV of the Arizona
21 Constitution and A.R.S. §§ 40-282 and 40-285.

22 2. The Commission has jurisdiction over AEPCO and the subject matter of the
23 application.

24 3. Notice of the proceeding was provided in conformance with law.

25 4. The stipulated rates and charges as set forth in and approved herein, and attached as
26 Exhibit A, are reasonable.

27 5. The recommendations set forth in the Findings of Fact discussed hereinabove are
28 reasonable and should be adopted in accordance with the discussion therein.

ORDER

IT IS THEREFORE ORDERED that the rates and charges set forth in Exhibit A are approved and Arizona Electric Power Cooperative, Inc. shall file on or before August 31, 2005, a tariff that complies with the rates and charges approved herein.

IT IS FURTHER ORDERED that the rates and charges for Phase One shall be effective for all service provided on and after September 1, 2005; the Phase Two rates shall be effective September 1, 2006; and Phase Three rates shall be effective September 1, 2007.

IT IS FURTHER ORDERED that within 15 days of the effective date of this Order, AEPCO shall notify its member/customers of the rates and the effective dates approved herein.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall file a rate case six months after Sulphur Springs Valley Electric Cooperative, Inc. has completed a full calendar year as a partial requirements member, or not later than five years after the effective date of this Decision, whichever is earlier.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall amend its tariffs to include a Fuel and Purchased Power Cost Adjustor as described herein.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. may file a request that the Commission review the efficacy of the FPPCA with Arizona Electric Cooperative, Inc.'s submission of any semi-annual FPPCA report required by this Decision.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall amend its tariff to include a DSM adjustor mechanism as discussed herein.

IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall file by March 31, 2006, an equity improvement plan that will indicate the effect on AEPCO's equity under the rates approved herein and an analysis of the effect on rates if equity of 30 percent of total capitalization is to be reached by 2015, as well as an analysis of the benefits and equities of capitalization on its partial requirements and full requirements members.

...

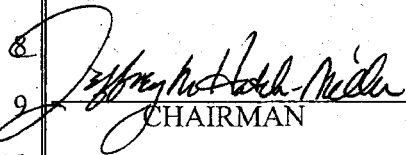
...

...

1 IT IS FURTHER ORDERED that Arizona Electric Power Cooperative, Inc. shall not make
2 any patronage refunds while its equity level remains below 20 percent of total capitalization, and
3 patronage refunds be limited to 25 percent of net earnings if its equity is between 20 and 30 percent
4 of its capitalization.

5 IT IS FURTHER ORDERED that this Decision shall become effective immediately.

6 BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

7
8 
9 CHAIRMAN

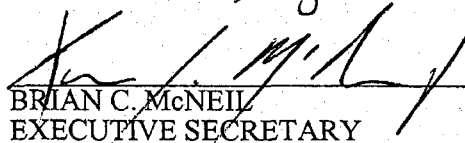

COMMISSIONER

10
11
12 
13 COMMISSIONER


COMMISSIONER


COMMISSIONER

14
15 IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive
16 Secretary of the Arizona Corporation Commission, have
17 hereunto set my hand and caused the official seal of the
18 Commission to be affixed at the Capitol, in the City of Phoenix,
19 this 17th day of Aug., 2005.

20 
21 BRIAN C. McNEIL
22 EXECUTIVE SECRETARY

23 DISSENT _____

24 DISSENT _____

25 JR:mj

1 SERVICE LIST FOR:

ARIZONA ELECTRIC POWER COOPERATIVE,
INC.

2
3 DOCKET NO.:

E-01773A-04-0528

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19 Ernest Johnson, Director
20 Utilities Division
21 Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

EXHIBIT A

Effective Date	September 1, 2005	September 1, 2006	September 1, 2007
All Requirements Members:			
Demand rate - \$/kW Month	14.31	14.64	14.98
Energy Rate - \$/kWh	0.02073	0.02073	0.02073
Power Cost Adjustor Base - \$/kWh	0.01687	0.01687	0.01687
Partial Requirements Members:			
Fixed Charge - \$/month	790,722	822,728	855,113
O&M Rate - \$/kWMonth	7.15	7.21	7.26
Energy Rate - \$/kWh	0.02073	0.02073	0.02073
Power Cost Adjustor Base - \$/kWh	0.01603	0.01603	0.01603

1 **BEFORE THE ARIZONA CORPORATION CC**

2 **COMMISSIONERS**

3 KRISTIN K. MAYES - Chairman
4 GARY PIERCE
5 PAUL NEWMAN
6 SANDRA D. KENNEDY
7 BOB STUMP

Arizona Corporation Commission

DOCKETED

SEP -8 2009

DOCKETED BY

nr

7 IN THE MATTER OF THE APPLICATION OF
8 SULPHUR SPRINGS VALLEY ELECTRIC
9 COOPERATIVE, INC. FOR A HEARING TO
10 DETERMINE THE FAIR VALUE OF ITS
11 PROPERTY FOR RATEMAKING PURPOSES, TO
12 FIX A JUST AND REASONABLE RETURN
13 THEREON, TO APPROVE RATES DESIGNED TO
14 DEVELOP SUCH RETURN AND FOR RELATED
15 APPROVALS.

DOCKET NO. E-01575A-08-0328

DECISION NO. 71274

OPINION AND ORDER

12 DATE OF HEARING: April 21, 22, and 23, 2009
13 PLACE OF HEARING: Tucson, Arizona
14 DATE OF PUBLIC COMMENT: February 11, 2009
15 PLACE OF PUBLIC COMMENT: Sierra Vista, Arizona
16 ADMINISTRATIVE LAW JUDGE: Jane L. Rodda
17 IN ATTENDANCE: Kristen K. Mayes, Chairman
18 Gary Pierce, Commissioner
19 Paul Newman, Commissioner
20 Sandra D. Kennedy, Commissioner
21 Bob Stump, Commissioner
22 APPEARANCES: Mr. Bradley S. Carroll, SNELL & WILMER, LLP, on
23 behalf of Applicant; and
24 Mr. Wesley C. Van Cleve and Mr. Kevin Torrey, Staff
25 Attorneys, Legal Division, on behalf of the Utilities
26 Division of the Arizona Corporation Commission.

27 **BY THE COMMISSION:**

Background

28 Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC" or "Cooperative") filed an
application for a rate increase with the Arizona Corporation Commission ("Commission") on June
30, 2008. SSVEC is a member owned non-profit cooperative that provides electric distribution

EXHIBIT

tabbies

5-11

1 services to approximately 51,000 customers in Cochise, Santa Cruz, Pima and Graham Counties,
2 Arizona.

3 The hearing in this matter commenced on April 21, 2009, in Tucson, Arizona. In addition, the
4 Commission conducted a Public Comment meeting in Sierra Vista on February 11, 2009.

5 This is SSVEC's first application for a rate increase since 1993, and the first one since
6 SSVEC became a Partial Requirement Member ("PRM") of Arizona Electric Power Cooperative
7 ("AEPCO") on January 1, 2008. SSVEC utilized a Test Year ended December 31, 2007. As
8 originally filed, SSVEC sought to increase its annual revenue by \$10,881,590, from adjusted Test
9 Year revenues of \$92,613,559 to \$103,495,149, an 11.75 percent increase.¹ The Cooperative stated
10 that it was requesting the rate increase in order to increase its equity by 1.5 to 2.0 percent per year to
11 reach a 30 percent equity level by 2014/2015; increase its annual cash flow; and meet its financial
12 objectives regarding the addition of new generation sources required by the continuing growth in its
13 service territory.

14 As its final position, SSVEC requests a rate increase of \$9,862,959, 10.63 percent over Test
15 Year revenues, for a revenue requirement of \$102,688,240,² which would yield Operating
16 Income/Margin³ of \$16,706,387 and Net Income/Margin of \$10,267,812. SSVEC's proposal results
17 in a 12.57 percent rate of return on Fair Value Rate Base, and yields a net operating Times Interest
18 Earned Ratio ("TIER") of 2.46 and a Debt Service Coverage ("DSC") of 2.25. SSVEC states this
19 translates into an increase for the average residential customer of 10.46 percent.

20 In addition to the rate increase, in its application, SSVEC requested that the Commission: (1)
21 approve a revision to its Wholesale Power Cost Adjustor ("WPCA") Mechanism to include the pass-
22 through of future generation and transmission costs associated with future Cooperative-owned
23 generation and transmission facilities;⁴ (2) implement a new Debt-Cost Adjustment mechanism that
24

25 ¹ Ex A-7 Hedrick Direct at 8.

26 ² Ex A-9 Hedrick Rebuttal, schedule DH-10.

27 ³ The Cooperative and Staff refer to Operating Margin and Net Margin instead of Operating Income and Net Income, the
28 terms are synonymous. Operating Income/Margin is Total Revenue less Operating Expenses. Net Income/Net Margin is
Operating Income/Margin less non-operating expenses, such as interest, plus non-operating income.

⁴ As such the Cooperative referred to the new mechanism as the Wholesale Power and Fuel Cost Adjustor ("WPFCA"),
while throughout the proceeding Staff continued to refer to the WPCA. Because Staff does not oppose the expansion of
the adjustor mechanism to include fuel costs if the Cooperative acquires generation assets, for uniformity the mechanism

1 would permit the Cooperative to recover increases in interest costs associated with Commission-
 2 approved financing of plant additions; (3) eliminate line extension credits pursuant to the
 3 Cooperative's line extension policy; (4) approve SSVEC's Demand Side Management ("DSM")
 4 Program (to the extent not already approved); (5) include a portion of approved future DSM program
 5 expenses in base rates and implement a revised DSM adjustor mechanism and approval process to
 6 recover approved DSM programs;⁵ and (6) revise its Tariffs and Service Conditions. Most of the
 7 public comment in this proceeding focused on SSVEC's planned upgrade of a transmission line in the
 8 Sonoita area. Some members in the Sonoita area question the need for the new line and have sought
 9 Commission intervention to stop its construction. Thus, in addition to the issues it raised in
 10 connection with its rate application, SSVEC presented evidence and argued that the upgrade of the
 11 existing transmission line serving the Sonoita area to a 69 kV line, known as the Sonoita Reliability
 12 Project, is needed to ensure reliable service in the area.

13 Staff recommends a revenue increase of \$7,595,316, or 8.18 percent, from adjusted Test Year
 14 revenues of \$92,825,281 to \$100,420,597. Staff's recommendation produces Operating Income of
 15 \$15,365,515,⁶ and Net Income of \$8,926,940.⁷ Staff's recommended revenue results in an 11.56
 16 percent rate of return on an adjusted rate base of \$132,886,202. Staff states that its recommended
 17 revenues would produce a TIER of 2.34 and DSC of 2.12. Staff claims that its recommended
 18 revenue level will increase SSVEC's equity to 30 percent of total capital by 2016, assuming the
 19 Cooperative utilizes \$3 million of its Net Income to reduce its projected long-term debt levels, and
 20 assuming that starting in 2013, SSVEC will borrow 10 percent less than the Cooperative currently
 21 projects.

22 After discovery, the Cooperative revised its requests, and decided not to pursue its request for
 23 a Debt-Cost Adjustment mechanism or to have a portion of its DSM Program expenses included in

24 will be referred to as the WPFCA when discussing the new mechanism and the WPCA when discussing the existing
 25 mechanism.

26 ⁵ Staff had originally recommended that SSVEC file a new application requesting approval of new DSM programs that it
 27 had proposed as part of this docket in order to allow an opportunity to gather information and to evaluate the new
 28 programs. SSVEC requested that the proposed programs be evaluated as part of this docket in order to have them
 implemented more quickly. The parties agreed that Staff would attempt to evaluate the proposed DSM programs as part
 of this docket and submit its recommendations as a late-filed exhibit.

⁶ Ex S-7 Brown Surrebuttal at 2.

⁷ *Id.*, Schedule CSB-8.

base rates. SSVEC and Staff have reached agreement on many issues, however, they continue to disagree about the level of revenue necessary to achieve a 30 percent equity ratio by 2016; several of Staff's adjustments to operating expenses; the process for resetting the WPFAC and the DSM Adjustor; whether a prudency review of power procurement activities should be required; and the appropriate level of the customer charge as part of the rate design.⁸

SSVEC believes that its ability to hold rates constant for 16 years and then request only a modest 10.46 percent revenue increase is something the Commission should view as a positive.⁹ SSVEC argues that the Cooperative should not be viewed by the Commission as a utility that is in need of more regulatory oversight.¹⁰ SSVEC believes that the primary issue in this rate case is its ability to build its equity to 30 percent of total capital by 2016, and it argues that Staff's recommendations would negatively affect the Cooperative's ability to meet this equity goal and should be rejected.

Rate Base

In its application, SSVEC proposed an Adjusted Rate Base of \$136,903,293. Staff recommended adjustments that reduced rate base by \$4,017,091, resulting in an Original Cost Rate Base ("OCRB") of \$132,886,202. Staff's rate base adjustments primarily affected consumer deposits, deferred credits and working capital.¹¹ SSVEC agreed to Staff's recommended adjusted OCRB.¹²

SSVEC did not prepare a Reconstruction Cost New Rate Base, and thus, its OCRB is deemed to be its Fair Value Rate Base ("FVRB").

Staff's adjustments to the Cooperative's proposed OCRB are reasonable and should be adopted. Consequently, SSVEC's FVRB is determined to be \$132,886,202.

...

...

⁸ The parties agree about the base cost of power, service conditions, and the establishment of written power procurement procedures. The design of Tie-Of-Use rates, the Bill Estimation Tariff and Tariff Changes.

⁹ SSVEC Opening Brief at 4.

¹⁰ *Id.*

¹¹ Ex S-6, Brown Direct at 8.

¹² SSVEC Opening Brief at 7.

1 Operating Income

2 Operating Revenues

3 The parties have agreed that adjusted Test Year revenues were \$92,825,281.

4 Operating Expense

5 Staff adjusted the Cooperative's Operating Expenses, reducing them by \$1,307,380, from
6 \$86,362,461 to \$85,055,081.

7 SSVEC agreed to adopt a number of Staff's proposed adjustments to Operating Income and
8 Expenses as follows:

- 9 No. 1 - Revenue Annualization - \$303,312
- 9 No. 1 - Expense Annualization - \$149,184
- 10 No. 3 - 2008 Fort Huachuca Contract - \$0
- 10 No. 4 - Base Cost of Power - \$10,523,837
- 11 No. 5 - DSM Expenses - (\$484,966)
- 11 No. 7 - GDS Expenses - (\$51,427)
- 12 No. 8 - Normalized Legal Expenses - (\$52,892)
- 12 No. 11 - Interest Expense on LTD - (\$426,301)
- 13 No. 12 - Capital Credits - (\$2,722,816)

14 SSVEC objects to Staff's recommended adjustments to Payroll Expense, "Incentive Pay",
15 Charitable Contributions, and Rate Case Expense.

16 Payroll Expenses

17 Staff reduced Payroll Expenses by \$523,570, from \$1,021,207 to \$497,637.¹³ Staff removed
18 the expenses associated with 10 employees who were hired in 2008 after the end of the Test Year.

19 Staff argues that it is not appropriate to include the additional 10 employees because SSVEC
20 did not demonstrate that the number of employees in the Test Year was abnormally low. Staff argues
21 that even if the expenses are known and measureable, there has been no showing that there was a
22 need for the added employees.¹⁴ Staff asserts that to include the expenses associated with the post-
23 Test Year employees creates a matching problem and that the Cooperative's argument that the
24 additional ten employees were needed to maintain service reliability misses the point of a Test
25 Year.¹⁵ In response to the Cooperative's claims that it is reasonable to include the costs associated
26 with the additional employees because of inherent regulatory lag and that waiting to hire additional

27 ¹³ Ex S-7 Brown Surrebuttal, Schedule CSB-15.

28 ¹⁴ Staff Reply Brief at 2.

¹⁵ Staff Reply Brief at 2.

1 staff until quality and service levels decline is not appropriate, Staff states that it is not suggesting
2 that SSVEC wait until service quality declines before hiring, but that SSVEC should file rate cases
3 more often than every 16 years.¹⁶

4 SSVEC argues that Staff's reduction of known and measurable post-Test Year expenses is not
5 appropriate. SSVEC states the employees at issue were hired within four months of the end of the
6 Test Year and remain on the payroll. SSVEC asserts that although Staff claims a matching problem is
7 created by including these post-Test Year expenses, Staff in other areas acknowledges that it is
8 appropriate to make proforma adjustments to reflect a reasonable expense going forward.¹⁷ SSVEC
9 asserts Staff's position ignores testimony by Mr. Hedrick that the payroll level proposed by SSVEC
10 represents the level of payroll needed to provide service quality and that the Cooperative has
11 experienced significant growth over the past five years.¹⁸ SSVEC believes Staff's position also
12 ignores that regardless of whether the expense is "allowed," the Cooperative will continue to pay
13 these ten employees, which would reduce its ability to improve equity.

14 The Commission considers post-Test Year adjustments on a case-by-case basis, in an attempt
15 to normalize Test Year results to reflect known and measureable changes to the Test Year. In this
16 case, although it does not appear that the 2007 staffing levels were abnormally low or "not normal,"
17 the Cooperative has demonstrated that its requested Payroll Expense represents a known and
18 measureable expense, as well as a continuous level of staffing. Staff believed that the employees
19 were hired to service growth in 2008 and future years.¹⁹ However, the Cooperative has shown that in
20 the five years commencing in 2003, it has experienced significant growth and that growth in staffing,
21 including the employees at issue, over the same period has grown proportionately.²⁰ The evidence
22 shows that the new employees were hired in early 2008 to achieve sufficient staffing levels to
23 maintain service quality arising from the high growth that occurred from 2003 through 2008, and
24 were not hired to serve growth that occurred after the Test Year. The Arizona Administrative Code
25

26 ¹⁶ Staff Opening Brief at 2-3.

27 ¹⁷ Citing Staff's adjustment to Interest Expense in this case to reflect an interest rate change that occurred 11 months after
the end of the Test Year.

28 ¹⁸ Ex A-8, Hedrick Rebuttal at 8-9.

¹⁹ Ex A-7 Brown Surrebuttal at 7.

²⁰ Ex A-8 Hedrick Rebuttal, Schedule DH 6.1.

1 allows for adjustments to actual test year results to obtain a normal or more realistic relationship
 2 between revenues and expenses and rate base.²¹ In this case, the proforma adjustment reflects a
 3 realistic staffing level and a known and measureable expense.

4 Year End Bonus and Safety Pay

5 Staff's adjustments removed \$45,058 from Payroll Expenses associated with expenditures that
 6 Staff characterizes as "Incentive Payments." Payments in this category comprise two components:
 7 \$24,558 related to safety performance, and \$20,500 related to year end bonuses. The Cooperative
 8 claims that these amounts have been consistently paid to all SSVEC employees for many years and
 9 are merely part of the entire compensation package.²² The year-end pay represents a \$100 payment
 10 to all employees made at the end of the year. Employees are entitled to safety pay for attending
 11 safety meetings and maintaining an accident-free record.²³ The average payment under the safety pay
 12 program in the Test Year was \$126.

13 Staff states that while it is not recommending that SSVEC cease paying its employees the
 14 bonuses or safety pay, they are optional costs that should not be recovered through rates.²⁴ To the
 15 extent that the Cooperative recovers these costs through rates, but elects not to award the incentives,
 16 Staff states the funds would become available for other activities.²⁵

17 Whether the Cooperative is required to pay year end bonuses or not, employees have come to
 18 expect a relatively small extra payment at the end of the year, which contributes to employee morale
 19 and satisfaction and is one factor that allows the Cooperative to retain its employees. The year end
 20 bonus is not tied to performance and is distinguishable from other situations where the Commission
 21 has not allowed the recovery of incentive pay/bonuses. Encouraging employees to attend safety
 22 meetings and maintain a safe record ultimately leads to lower costs.

23 Charitable Contributions

24 Staff reduced Charitable Contributions and Other Expenses by \$298,622, from \$343,752 to
 25

26 ²¹ A.A.C. R14-2-103(p).

27 ²² *Id.* at 11; Ex A-9 Hedrick Rejoinder at 4.

28 ²³ Transcript of the April 21, 2009 hearing ("Tr.") at 289.

²⁴ Staff Opening Brief at 4.

²⁵ *Id.*

1 \$45,150.²⁶ Staff removed expenditures for charitable contributions, sponsorships, gifts, and awards,
2 meals and employee parties and entertainment.

3 Staff argues that charitable contributions should be disallowed because they are not needed to
4 provide service, and the mere fact that the Commission allowed these expenses in the past does not
5 mean that the Cooperative is entitled to recover the expense in the current case. Staff states that in
6 other recent rate cases the Commission has disallowed charitable expenses.²⁷ Because the decision of
7 how much to donate, or whether to donate at all, is entirely within the discretion of SSVEC
8 management, Staff believes that in the absence of a mandate to provide such charitable donations,
9 there should be no guaranteed revenue stream for those purposes.²⁸

10 SSVEC argues that Staff's disallowance of Charitable Expenses is contrary to Decision No.
11 58358 (the 1993 Rate Decision) in which the Commission allowed the recovery of such expenses.
12 SSVEC noted that with respect to Charitable Contributions, Decision No. 58358 provided:

13 These expenses go to the difficult issue of the role of a Cooperative today.
14 We are mindful of the impassioned arguments made by members of the
15 Cooperative and its board of directors during the public comment session
16 who said that these expenses are appropriate for SSVEC's rural
17 community; that the activities supported may be the only ones available to
18 young people in the area and may not otherwise take place; and, that
19 SSVEC's support is essential for much needed economic development.
20 Additionally, we recognize that the cost of SSVEC's support for all of
21 these expenses averaged but \$1.76 per customer per year. Were this an
22 investor-owned-utility, we could require that the investors, not the
ratepayers, bear the cost of the corporation's community mindedness.
With a cooperative the ratepayers cannot be separated from their member-
owners. For these reasons, we will allow the costs in the instant case.
However, we share the view of RUCO and Staff that members' choices
are made for them. Therefore, we will require SSVEC, in its next rate
proceeding, to demonstrate that a majority of its members have ratified the
Board's expenditure of their funds for these purposes. If it does not, we
will disallow the expenditures. To fairly gauge its members' desires
SSVEC should:

- 23 a. prepare a ballot for each of its members containing
sufficient information to explain the expenses at issue;
- 24 b. submit a draft of the ballot to the Director of the Utilities
Division for approval/modification; such
25 approval/modification shall be provided within 15 days of
receipt;
- 26 c. mail the approved ballot to each member; and
- d. receive the approval of a majority of the members voting

27 ²⁶ Ex S-7, Brown Surrebuttal, Schedule CSB-18.

28 ²⁷ Staff Opening Brief at 3.

²⁸ Staff Reply Brief at 4.

and returning the ballots within 30 days of SSVEC's mailing of the ballots.²⁹

SSVEC asserts that the evidence presented at the hearing demonstrates that: (1) the Cooperative initiated the by-law change in 1997, (ii) the Cooperative filed the proposed change to its by-laws with the Commission's Director of Utilities; (iii) the by-law change was submitted to the Cooperative's members and was approved by over a 90 percent margin; and (iv) SSVEC donations and sponsorship programs have been widely accepted and acclaimed by its members.³⁰ Furthermore, SSVEC asserts, as in the prior rate case, Mr. Blair testified why it is important for a rural cooperative to be able to continue to make charitable contributions; the February 11, 2009, public comment session demonstrated there is public support for the Cooperative's charitable programs; and Mr. Blair testified that charitable programs account for only about 3 percent of total revenues.³¹

SSVEC argues this is a very important issue as it underscores the difference between an investor-owned utility and a member-owned cooperative and the role of the cooperative in the rural community. SSVEC asserts that if its members were unwilling to support the Cooperative's ability to maintain these programs in favor of either lower rates or a return through capital credits, they would not have approved the by-law change by such an overwhelming margin. SSVEC states if members decide they do not want the Cooperative to continue such programs, they can initiate such a change through the Board. Furthermore, SSVEC states that if Staff's adjustment is adopted, the Cooperative will have to pay for these programs from its net income/ margins, which would be inconsistent with the goal of reaching a 30 percent equity level by 2016.

The Cooperative has shown that it complied with the directives of Decision No. 58358 by initiating the by-law change, filing the by-law change with the Commission Utilities Director; and submitting the by-law change to its members (where it was adopted by a 90 percent margin). SSVEC claims that its donations and sponsorships have been widely accepted and acclaimed by its members.³² There is no indication that member/ratepayers are opposed to the Cooperative's charitable donations, and the record indicates there is support for the Cooperative's involvement in

²⁹ Decision No. 58358 at 18 and 19.

³⁰ Ex A-18 Blair Rebuttal at 13-16; Rebuttal Exhibits JB-1 and JB-2, Tr at 341-48.

³¹ *Id.* at 13; see also Transcript of February 11, 2009 Public Comment session.

³² Ex A-18 at 13-17; Rebuttal Exhibits JB-1 and JB-2; Tr. at 341-48.

1 the community.³³ On the other hand, member/ratepayers are concerned about the impact of the rate
 2 increase and at least one member mentioned the role of charitable contributions as part of the need for
 3 increasing rates.³⁴

4 The by-law change that was submitted to members in 1997 for approval states:

5 ARTICLE IV – DIRECTORS. SECITON 4.07. Rules, Regulations, Rate
 6 Schedules and Contracts. The Board of Directors shall have power to
 7 make, adopt, amend, abolish and promulgate such rules, regulations,
 8 policies, rate schedules, contracts, security deposits and any other types of
 9 deposits, payments or charges, including contributions in aid of
 construction, advertising, and donations not inconsistent with law or the
 Cooperative's Articles of Incorporation or Bylaws, as it may deem
 advisable for the management, administration and regulation of the
 business and affairs of the Cooperative.

10 Mr. Blair testified that the by-law change added the power to make and adopt advertising and
 11 donations to the list of powers given to the Board of Directors.³⁵ Although the revised by-law
 12 provision gives the Cooperative's Board of Directors the power to make donations, it does not in and
 13 of itself, indicate that such donations will affect rates. We do not know what members were told in
 14 1997 about how donations would be treated for ratemaking purposes as current management was not
 15 around at the time. The Cooperative has admitted that it has grown significantly in the past five
 16 years, and consequently, there are many more members now than in 1993, which makes it reasonable
 17 to re-examine the previous treatment of these expenditures. The previous rate Decision did not
 18 guarantee that charitable expenses would be allowed, even if the Cooperative complied with the
 19 directive to change the Bylaws. It is not clear whether current members are aware that the
 20 Cooperative's charitable donations and sponsorships can affect their rates. Although we recognize
 21 their importance to the community, we do not believe that charitable contributions and sponsorships
 22 are appropriate above-the-line expenses that should be collected from ratepayers. Consequently, we
 23 adopt Staff's recommendation to disallow these expenses. This is not to say that the Cooperative
 24 cannot, and should not, continue to make appropriate contributions at the discretion of the Board of
 25 Directors. As a member-owned cooperative we expect that the Cooperative will probably continue to
 26 make contributions, and we are mindful that to the extent the Directors elect to make such

27 ³³ E.g. See Transcript of the February 11, 2009 Public Comment at 50-55.

28 ³⁴ *Id.* at 47.

³⁵ Ex A-18. Blair Rebuttal at 15.

1 contributions it will affect the Cooperative's bottom line, and as such, in combination with other
2 factors may affect how quickly the Cooperative is able to build equity. We do not believe, however,
3 that maintaining the current level of contributions will substantially impair the Cooperative's ability
4 to improve its equity. As optional expenses, the Board of Directors must balance various factors to
5 determine the appropriate level of charitable contributions, just as they do with the return of capital
6 credits.

7 Rate Case Expense

8 Staff and SSVEC disagree about the appropriate level of Rate Case Expense.

9 In its Application, SSVEC had included \$100,000 of Rate Case Expense, that it proposed be
10 recovered over five years, for a \$20,000 annual Rate Case Expense. SSVEC states that the \$100,000
11 represented the approximate amount of expenses that it had incurred at the time it filed the rate
12 application. In her direct testimony, Rebecca Payne testified that: "actual rate case expense will only
13 be known at the time of the hearing/settlement. Schedule RAP-2 shows invoices related to this case
14 incurred up to the filing. We propose to provide invoices to ACC Staff for all additional rate case
15 related expenses for a final determination of rate case expense."³⁶

16 In rebuttal testimony, the Cooperative revised its total Rate Case Expense to \$310,000 to
17 reflect the legal and consulting fees that it had incurred as of February 27, 2009. SSVEC estimated it
18 would incur an additional cost of \$87,000 through the hearing. SSVEC requested a total Rate Case
19 Expense of \$397,608, recovered over a five-year period for an adjusted annual Rate Case Expense of
20 \$79,522. Thus, it was seeking an additional \$59,522 in annual Rate Case Expense over the amount
21 originally requested. In response to a data request, SSVEC provided Staff with invoices for the
22 expenses that had been incurred.

23 In its direct case, Staff included, without comment, the \$20,000 of annual Rate Case Expense
24 as initially filed by the Cooperative. After receiving the Company's revised Rate Case Expense as set
25 forth in Rebuttal Testimony, Staff did not modify its original position concerning Rate Case Expense,
26 and recommends disallowing the additional \$59,522 of annual Rate Case Expense.

27

28 ³⁶ Ex A-15, Payne Direct at 7.

Staff believes that had SSVEC been more proactive in managing its Rate Case Expense it could have avoided quadrupling those costs. Staff asserts that SSVEC could have avoided the increase in the Rate Case Expense by (1) determining a rate case budget, (2) evaluating the strength of the issues in the case, and (3) assessing the marginal benefit of each cost. Staff states that SSVEC did none of these things to manage Rate Case Expense and recommends that all of SSVEC's Rate Case Expense above the original \$100,000 estimate be disallowed as unreasonable.³⁷ Staff states that because SSVEC did not provide a detailed budget of Rate Case Expense, Staff was left with "no reasonable alternative but to recommend allowance of SSVEC's original estimate of rate case expense."³⁸ Staff believes the issue is one of prudence, and that in the absence of documentation to support the Cooperative's activities, "there is no way to make that determination."³⁹ Staff argues the legal expenses incurred by other utilities is not determinative of what was prudent in this case.⁴⁰ Staff states that its treatment of Rate Case Expense is consistent with SSVEC's last rate case.⁴¹

SSVEC notes that the original \$100,000 that the Cooperative proposed for total Rate Case Expense was not an estimate, as the testimony is clear that it was the amount of expense that was known at the time of filing, and that the Cooperative would be revising the number.⁴² SSVEC also argues that Staff offered no evidence in support of its contention that SSVEC could have managed its rate case expense to avoid quadrupling the original estimate of \$100,000. SSVEC asserts that many of the issues that arose in this case could not have been anticipated from the outset, including the large number of data requests (17 sets and 268 questions); the need to engage a power procurement witness to respond to Staff; a three-day hearing; the injection of the 69 kV line issue; the additional public comment session; and issues Staff initiated such as the recommendation to approve the WPFAC increases and the reset of the DSM adjuster.⁴³ SSVEC asserts that Staff fails to address the fact that Staff reviewed the invoices and had no problem with them, that the Commission has awarded other utilities more in rate case expense than is being requested here; that as a cooperative,

³⁷ Ex S-7, Brown Surrebuttal at 9-10, Tr. at 361.

³⁸ Staff Opening Brief at 5.

³⁹ Staff Reply Brief at 4.

⁴⁰ *Id.* at 4.

⁴¹ Staff Opening Brief at 5.

⁴² Ex A-15, Payne Direct at 7.

⁴³ SSVEC Opening Brief at 25.

1 there are no shareholders to bear the uncovered amount of Rate Case Expense; that when it prepared
 2 its rate case, SSVEC had no way to know how many data requests would be issued or what additional
 3 issues would be included in the rate proceeding; that in order to mitigate the rate impact, the
 4 Cooperative is proposing to spread Rate Case Expense over five years instead of the more typical
 5 four years; that this rate case could not have been litigated for \$100,000; that the Cooperative had to
 6 answer the data requests propounded by Staff whether it had a budget or not; and that any un-
 7 recovered Rate Case Expense would be paid from Operating Income which would have a negative
 8 impact on equity growth.

9 SSVEC presented a comparison of Rate Case Expense amounts that have been allowed in
 10 other rate case filings:⁴⁴

<u>Utility</u>	<u>Decision No.</u>	<u>Date</u>	<u>Revenue Requirement</u>	<u>No. Customers</u>	<u>Approved Rate Case Expense</u>	<u>Amort period</u>
12 UNS Electric	70360	5/27/08	\$171,631,367	93,000	\$300,000	3
13 Arizona American Water	70351	5/16/08	\$9,711,596	23,000	\$94,264	4
14 UNS Gas	70011	11/27/07	\$178,393,000	140,000	\$300,000	3
15 Far West Water & Sewer	69335	2/20/07	\$1,900,786	5,500	\$160,000	3
16 Black Mountain Sewer	69164	12/5/06	\$1,375,037	1,957	\$150,000	4
17 Arizona Water Company	68302	11/14/05	\$12,140,321	20,266	\$250,000	3
18 Chaparral City Water	68176	9/30/05	\$7,795,935	12,000	\$285,000	4
19 Pine Water Company	67166	8/1-/04	\$922,984	2,000	\$200,000	4
20 Arizona-American Water	67093	6/30/04	\$10,331,873	15,000	\$418,941	3
21 Arizona Water Company	66849	3/19/04	\$18,909,627	29,000	\$250,000	3

22 We do not believe it is reasonable to hold a company strictly to its original estimate of Rate
 23 Case Expense regardless of intervening events. SSVEC provided invoices supporting all of its Rate
 24 Case Expense up to the hearing, and there is no indication that the expenses were unreasonable. This
 25 was a complex rate case because it was the first time either SSVEC was being reviewed as a PRM of
 26 AEPCO—a first not only for the Cooperative, but for Staff. In addition, the Cooperative had not

27
 28 ⁴⁴ SSVEC Opening Brief at Attachment A. By way of comparison, SSVEC requested revenue of \$102,495,149, has 51,000 customers and requested Rate Case Expense of \$397,606 amortized over 5 years.

1 prepared a rate case in 16 years. There was a large number of data requests, new issues of fuel
 2 procurement and the injection of the issue of the Sonoita Reliability Project. Some of the rate case
 3 expenses were incurred as a result of the need to respond to a unique circumstance or issues of first
 4 impression, that are not likely to arise in the future as both the Cooperative and Staff gain experience
 5 with SSVEC as a PRM. In this case, we find that a total Rate Case Expense of \$300,000 is fair and
 6 reasonable, and represents a more realistic level of total Rate Case Expense. Spreading recovery of
 7 this over ten years results in an annual adjusted Rate Case Expense of \$30,000, which we find is an
 8 appropriate level of Rate Case Expense. SSVEC was not definitive about when it expects to file its
 9 next rate case, but projects between three and eight years.⁴⁵ Given that it has been 16 years since
 10 SSVEC's last rate case, and given the surplus recovery of SSVEC's prior rate case expenses, we
 11 believe it is appropriate to amortize SSVEC's rate case expenses over ten years. The ten year
 12 recovery period we adopt is longer than usually seen for an investor-owned utility, but not
 13 unreasonable in light of the circumstances of this case.

14 Test Year Operating Income

15 With respect to Payroll Expenses, Year End Bonus and Safety Pay and Charitable Expenses,
 16 we adopt Staff's adjustments. As discussed herein, we adjust Staff's recommended recovery of Rate
 17 Case Expense. Based on the foregoing, we determine adjusted Test Year Revenues and Operating
 18 Expenses as follows:

19	Total Revenues	\$92,825,281
20	Total Expenses	\$85,105,081
	Operating Income	\$ 7,720,200
21	Interest Expense & Other Deductions	\$ 7,106,255
22	Non-Operating Additions	\$ 667,660
	Net Income	\$ 1,281,605

23 Thus, in the Test Year, the Cooperative experienced a return on FVRB of 5.81 percent.

24 Revenue Requirement

25 SSVEC and Staff agree that the Cooperative's goal of increasing its equity to 30 percent of
 26 total capital by 2016 is reasonable. They disagree, however, on the level of revenue that would be
 27

28 ⁴⁵ Tr. at 84-85.

1 required to reach this goal.

2 Staff argues that its recommended revenue level will allow SSVEC to achieve the 30 percent
3 equity goal. Staff assumes SSVEC will pay down its long-term debt by utilizing \$3 million from its
4 Net Income, and that SSVEC's future borrowing will be 10 percent lower than SSVEC has projected
5 because the Cooperative's growth rates will slow due to economic conditions.⁴⁶ Staff asserts that
6 SSVEC developed its revenue requirement in part to allow for higher capital credit retirements,⁴⁷ and
7 made assumptions about long-term debt that are not reasonable, which led Staff to reduce those
8 assumptions by 10 percent.⁴⁸ To the first point, Staff believes that given the current economic
9 difficulties nationwide, "it is not an appropriate time to increase the amount of money taken from
10 members, simply for the stated purpose of increasing the amount of money to be returned to them in
11 the future."⁴⁹ Based on public comment, Staff does not believe there is member support to increase
12 capital retirements.⁵⁰ Secondly, Staff asserts that SSVEC admitted that its debt projections
13 represented the minimum amount of debt that it could incur, not that it would incur.⁵¹ Moreover,
14 Staff notes that its revenue requirement results in a DSC of 2.12, which exceeds the minimum
15 requirement of SSVEC's lender, the Cooperative Finance Corporation ("CFC"), which only requires
16 a DSC of 1.35.

17 SSVEC asserts there is no basis for Staff to lower projected long-term debt by \$3 million.
18 SSVEC claims that Staff could not explain why it was appropriate for SSVEC to utilize \$3 million of
19 its net income to reduce its long-term debt.⁵² SSVEC states that under Staff's analysis, the
20 Cooperative would be \$3 million short each year in its efforts to build equity. In addition, SSVEC
21 asserts there is no basis for Staff's assumption that SSVEC's debt will fall by 10 percent in 2012, as
22 there is no evidence in the record to support the claim. Staff testified that because of the "bad
23 economy" Staff does not believe that the Cooperative will grow at the same pace and will not need to

24

25 ⁴⁶ Staff Opening Brief at 6.

26 ⁴⁷ The Cooperative's Board of Directors determines annually how much of its Net Income should be returned to its members in the form of retired capital credits.

27 ⁴⁸ Tr. at 396-397.

28 ⁴⁹ Staff Reply Brief at 2.

⁵⁰ *Id.* at 2.

⁵¹ Tr. at 242.

⁵² SSVEC Reply Brief at 4-5, citing Tr at 389-391 and 394.

1 borrow as much.⁵³ SSVEC argues Staff's 10 percent reduction in long-term debt levels in 2012 was
 2 an arbitrary determination made to justify lowering the revenue requirement.⁵⁴ The Cooperative
 3 notes that Mr. Huber testified that the Cooperative's level of capital projects would continue into the
 4 future which would necessitate its current level of borrowing.⁵⁵ SSVEC asserts that Staff offered no
 5 evidence about the Cooperative's level of growth or need for plant additions. Consequently, SSVEC
 6 argues Staff's assumptions are without foundation, and asserts that Mr. Huber is the person with the
 7 most direct knowledge about the capital needs of the Cooperative. SSVEC states further, that it was
 8 being conservative in its projections by using the minimum amount of debt that it will need.⁵⁶

9 SSVEC asserts that Staff's adjustments to income were arbitrary and made solely to reduce
 10 the rate increase. SSVEC argues that speculation and arbitrary assumptions are not substantial
 11 evidence and cannot be determinative.⁵⁷ SSVEC argues that its requested revenue requirement was
 12 developed to allow it to reach 30 percent equity capitalization within a reasonable period, and that
 13 Staff's suggestion that it is seeking additional revenues to fund higher capital credit retirement is
 14 baseless. SSVEC notes that Mr. Huber testified that it would not be until after the Cooperative
 15 reached 30 percent equity that it would seek higher capital credit retirement.⁵⁸

16 We find that Staff's revenue requirement, adjusted to reflect our determination of the recovery
 17 of Rate Case Expense, of \$100,430,597 will allow the Cooperative to meet its lender's required
 18 financial ratios and achieve a 30 percent equity ratio in a reasonable period of time. This revenue
 19 level is an increase of \$7,605,316 or 8.19 percent, over Test Year revenues.

20 Rate Design

21 Customer Charge

22 SSVEC seeks to increase its monthly customer charge by \$5.00, from \$7.50 to \$12.50 for
 23 residential customers, and seeks similar increases in the monthly customer charge for other customer
 24 classes. Staff recommends an increase in the monthly residential customer charge of \$0.75 from
 25

26 ⁵³ Tr. at 396-397.

⁵⁴ SSVEC Reply Brief at 6.

⁵⁵ Tr. at 85-87.

⁵⁶ SSVEC Reply Brief at 7.

⁵⁷ *City of Tucson v. Citizens Utilities Water Company*, 17 Ariz. App. 477, 481 P.2d 551, 555 (Ct. App. 1972).

⁵⁸ SSVEC Reply Brief at 7, citing Tr. at 233 and 249.

1 \$7.50 to \$8.25. With the exception of the amount of the customer charges, SSVEC has agreed to
2 Staff's recommend time-of-use rates ("TOU").⁵⁹

3 SSVEC presented a cost study that shows the cost of serving a residential customer is \$23.31
4 per month. Staff accepts the Cooperative's cost study. SSVEC argues that its proposed increase in
5 the customer charge is more reflective of the cost of providing service, and that to send a proper
6 pricing signal, the fixed customer charge component of the rate should be increased closer to the
7 actual cost. SSVEC states that while Staff's characterization of the customer charge as a 67 percent
8 increase is technically correct for a customer with no kWh usage, it is misleading because it singles
9 out only one component of the requested increase.⁶⁰

10 SSVEC also notes that the Commission has previously approved increases in customer
11 charges for other cooperatives which are similar to those SSVEC requests in this case. For example,
12 SSVEC notes that in its last rate cases, Trico's residential customer charge was increased from \$8.00
13 to \$12.00 per month, and Navopache's residential customer charge was increased from \$11.25 to
14 \$18.30 per month.

15 Staff notes that the Cooperative admits that an increase in the customer charge promotes the
16 de-coupling of rates, thereby making SSVEC less dependent upon the sale of energy to recover its
17 distribution costs.⁶¹ Staff believes that its proposal, under which the Cooperative would recover 35
18 percent of the customer related costs, is a more reasonable step than the Cooperative's proposal
19 which recovers 54 percent of customer related costs.⁶² Staff believes it is unreasonable to expect
20 customers to "absorb increases that average 63.08 % in one step."⁶³ Staff claims that a significant
21 increase in the monthly customer charges makes it more difficult for customers to implement
22 conservation measures to reduce the amount of the total monthly bill.

23 The following lists the current, Staff proposed and SSVEC proposed monthly customer
24 charges:

25
26 ⁵⁹ SSVEC Opening Brief at 10.

27 ⁶⁰ Ex A-9 Hedrick Rejoinder at 16.

28 ⁶¹ Ex A-8 Hedrick Rebuttal at 21.

⁶² Staff Opening Brief at 15.

⁶³ *Id.* at 5-9; Ex S-9 Musgrove Surrebuttal at 3.

	<u>Current</u>	<u>Staff</u>	<u>SSVEC</u>
Residential	\$7.50	\$ 8.25	\$12.50
Residential TOU	\$11.40	\$13.25	\$13.25 ⁶⁴
GS (Non-Demand)	\$11.50	\$13.50	\$17.50
GS Demand	\$11.50	\$13.35	\$17.50
GS TOU	\$12.75	\$14.45	\$21.50
Large Power	\$42.00	\$44.25	\$75.00
LP Seasonal	\$50.00	\$56.25	\$75.00
LP TOU	\$43.84	\$44.45	\$100.00

We will adopt Staff's proposed monthly customer charges.

Service Related Charges

SSVEC's current service charges and the recommended charges are as follows:⁶⁵

	<u>Existing</u>	<u>SSVEC proposed</u>	<u>Staff recommended</u>
Return Check	\$15.00	\$25.00	\$25.00
Existing Member Connect Fee-Regular Hours	25.00	50.00	40.00
Connect Fee-After hours	45.00	75.00	75.00
New Connects	0.00	50.00	50.00
Non-Pay Trip Fee – Regular Hours	25.00	50.00	40.00
Non-Pay Trip Fee – After hours	45.00	75.00	75.00
Service Charge Regular Hours	45.00	50.00	50.00
Service Charge After hours	45.00	75.00	75.00

Staff and SSVEC agree on all service fee charges except for Existing Member Connect-Regular Hours and Non-Pay Trip Fee- Regular Hours. SSVEC is proposing \$50 for each of these charges, while Staff is recommending \$40.

SSVEC argues that its proposed increase in service related charges moves the charges closer to the actual cost of providing the service, and helps to mitigate the need for the Cooperative to subsidize the costs of these services. The Cooperative's studies indicate the cost of the Member

⁶⁴ The Cooperative initially proposed a \$16.50 customer charge for Residential TOU, but the Cooperative subsequently adopted the Staff's proposed TOU rates. Accordingly, we will approve Staff's proposed customer charge of \$13.25 to prevent over-collection from the Residential TOU customers.

⁶⁵ Those in bold are the only disputed charges.

1 Connect Fee to be \$94.78 and the Non-Pay Trip Fee to be \$138.29.⁶⁶

2 Staff asserts that the difference between what SSVEC is proposing and what Staff is
3 recommending with respect to these two services would produce approximately \$200,000 in
4 additional revenues, which is more than a de minimus amount.⁶⁷ Staff could not incorporate the \$50
5 fee for these charges in its rate design without producing a material amount of additional revenue
6 over the amount of the total revenue increase being recommended. Furthermore, Staff argues its
7 proposed increases for the disputed charges are supported by increases experienced in related labor
8 costs over the 16 year period since SSVEC's last rate case.

9 SSVEC claims that Staff's recommended allocations have no bearing on whether the
10 Cooperative's proposed service charges are just and reasonable.⁶⁸ SSVEC asserts that Staff's
11 approach that considered the increase in the cost of labor since 1993 did not take into account
12 whether the rate established in 1993 covered the Cooperative's actual cost of providing the service.⁶⁹
13 SSVEC argues that to the extent the Cooperative was not recovering its costs in 1993, it is not the
14 appropriate starting point to set the rate in 2009. The Cooperative believes that the establishment of
15 appropriate service charges is a clear way to achieve the Commission expressed goal -- that to the
16 extent practical, the costs of providing the service should be borne by those who cause the costs to be
17 incurred.⁷⁰

18 We believe Staff's recommended service charges are reasonable.

19 **Residential TOU Participation**

20 The Commission is concerned by the lack of participation in the Cooperative's Residential
21 TOU program, and believes this may signal that the Cooperative's Residential TOU program does
22 not offer ratepayers a realistic opportunity to save money by shifting their usage to off-peak hours.
23 We will require the Cooperative to submit an annual report to the Commission detailing the total
24 number of Residential TOU ratepayers and the savings or losses experienced by the participants on
25 the Residential TOU plan.

26 ⁶⁶ Ex A-8 Hedrick Rebuttal at 24; Schedule DH-21.

27 ⁶⁷ Tr. at 477-478.

28 ⁶⁸ SSVEC Reply Brief at 28.

⁶⁹ SSVEC Opening Brief at 51.

⁷⁰ Ex A-9, Hedrick Rejoinder at 17.

If, after two years from the effective date of this Decision, less than 10 percent of eligible ratepayers are participating in Residential TOU plan, we will require SSVEC to file a plan, for Commission approval, to increase participation in the Residential TOU plan to at least 10 percent. The plan may include, among other things, additional advertising of the Residential TOU plan or modifications to the on-peak/off-peak hours or rates of the Plan.

Demand Side Management and Renewable Energy Standard Tariff

As part of this application, SSVEC submitted for Commission approval three new DSM programs and modification to one of its existing programs. The proposed new programs include: (1) an Energy Efficient Water Heater Rebate Program; (2) the Commercial and Industrial Energy Efficiency Improvement Loan Program ("C&ILP") and (3) the Energy Efficient New Home or Remodel Rebate Program. SSVEC proposed modifications to its existing loan program which is now being called the Energy Efficient Improvement Loan Program ("EEILP"). As previously noted, the parties agreed that in lieu of filing a separate application for approval of the new DSM programs, Staff would make its recommendations concerning the DSM programs in a late-filed exhibit to this proceeding.⁷¹

DSM and Renewable Energy Standard Tariff Adjustor mechanisms

In its pre-hearing testimony, Staff enumerated sixteen recommendations relating to DSM and the Renewable Energy Standard Tariff ("REST").⁷² Staff recommends as follows:

1. SSVEC file with Docket Control a revised version of the DSM program description that removes reference to Time-of-Use ("TOU") rates and controlled rate program for irrigators;
2. Costs prudently incurred in connection with Commission-approved DSM activities be recovered entirely through a DSM Adjustment Tariff;⁷³
3. Commission-approved DSM costs should be assessed to all SSVEC electric customers as a clearly labeled single line item per kWh charge on customer bills;

⁷¹ Staff addressed its recommendations concerning the DSM adjustor mechanism in its pre-hearing testimony and made recommendations concerning the new DSM programs and the 2007 and 2008 DSM program expenses in the Supplemental Testimony of Steve Irvine dated May 22, 2009.

⁷² Ex S-10, Irvine Direct at 23-25.

⁷³ Heretofore, SSVEC recovers DSM program costs through its WPCA.

- 1 4. Should the Commission approve SSVEC's recommendation to include some part
2 of DSM program expense in base rates, it should be clarified that a negative
3 DSM adjuster may be used to lower DSM program expense recovery below the
4 rate included in base rates;
- 5 5. SSVEC continue to report on DSM program expenses semi-annually;⁷⁴
- 6 6. SSVEC file the DSM program expense reports in Docket Control and that
7 SSVEC redact any personal customer information;
- 8 7. SSVEC's DSM program expense reports should include the following: (i) the
9 number of measures installed/homes built/participation levels; (ii) copies of
10 marketing materials; (iii) estimated cost savings to participants; (iv) gas and
11 electric savings as determined by the monitoring and evaluation process; (v)
12 estimated environmental savings; (vi) the total amount of the program budget
13 spent during the previous six months and, in the end of year report, during the
14 calendar year; (vii) the amount spent since the inception of the program; (viii)
15 any significant impacts on program cost-effectiveness; (ix) descriptions of any
16 problems and proposed solutions, including movements of funding from one
17 program to another; (x) any major changes, including termination of the
18 program. SSVEC should file its new proposed DSM adjustor rate with Docket
19 Control by March 1st of each year, and that such filing be considered and
20 adjudicated by the Commission in Open Meeting;⁷⁵
- 21 8. SSVEC's DSM adjustor rate be reset annually on June 1st of each year and that
22 the per kWh rate be based upon currently projected DSM costs for that year (the
23 year for which the calculation is being made) adjusted by the previous year's
24 over- or under-collection, divided by projected retail sales (kWh) for that same
25 year;

26
27 ⁷⁴ The parties have agreed that the semi-annual reports should be filed by March 1st (for the period July through
December) and by September 1st (for the period January through June).

28 ⁷⁵ Staff originally recommended the DSM adjustor reset be filed by April 1st, but agreed with the Cooperative's request to
have the DSM adjustor reset filing due at the same time as its adjustor report. See Staff Opening Brief at 8-9.

- 1 9. SSVEC's annually proposed new DSM adjustor rate become effective on June
- 2 1st after approval by the Commission;
- 3 10. SSVEC submit proposed programs to the Commission for approval;
- 4 11. SSVEC file an application requesting approval of the new DSM programs
- 5 proposed by SSVEC as part of this rate application;⁷⁶
- 6 12. The initial DSM adjustor rate be set to recover prudently incurred DSM costs
- 7 associated only with approved programs presently in place;
- 8 13. Prudently incurred costs associated with approved DSM programs that have been
- 9 factored into the WPCA/WPFCA account balance remain in the WPFCA
- 10 account balance;
- 11 14. The adjustor rate be set at \$0.00088 per kWh⁷⁷ until the annual reset of the
- 12 adjustor rate;
- 13 15. The Commission authorize an adjustor mechanism for SSVEC to replace the
- 14 REST Surcharge; and
- 15 16. SSVEC file with the Commission a REST tariff with conforming changes within
- 16 30 days of the date of the Decision in this case to reflect recovery through the
- 17 adjustor rather than through the surcharge used currently.

18 SSVEC agrees to Staff's recommendations, except that SSVEC argues that the June 1st reset
 19 date (Recommendation No. 9) should be a "hard" deadline, such that the new DSM adjustor rate
 20 would go into effect automatically unless the Commission acts prior to June 1.

21 Staff argues that SSVEC's position for an automatic reset of the DSM adjustor is not
 22 appropriate. Staff asserts that having the DSM adjustor rate adjudicated by the Commission will
 23 allow the Commission to directly manage recovery of DSM costs and consider the impact on
 24 ratepayers. Staff believes that because changes to the DSM adjustor rate have a direct impact on
 25 customer bills, it is appropriate that the adjustor rate be reset by order of the Commission. Staff notes
 26 further that there is no need for an automatic reset of the DSM adjustor rate because SSVEC would

27 ⁷⁶ As stated previously, Staff agreed to review and recommend SSVEC's new DSM programs as part of this proceeding.

28 ⁷⁷ Originally Staff recommended \$0.000256 per kWh, but revised the figure after Staff's recommendations for the new DSM programs.

1 be able to continue to recover its DSM program expenses through the existing rate. Staff states that
 2 uncollected expenses are recorded in the DSM adjustor account and can be recovered through future
 3 rates, and that in the long run SSVEC would see no loss for having waited to implement a new
 4 adjustor rate.

5 SSVEC is concerned that even by filing its proposed DSM adjustor rate by March 1 of each
 6 year, the Commission is unlikely to be in a position to approve the filing on or before June 1.⁷⁸
 7 According to SSVEC, its proposal for an automatic adjustment absent Commission action would not
 8 deny the Commission the opportunity to consider and approve the matter; provides flexibility; gives
 9 the Commission 90 days to act; allows the Commission to "true-up" the adjustor the following year;
 10 gives the Cooperative certainty by not having to wait to recover additional program expenses; and
 11 would give SSVEC more motivation to promote and expand DSM programs.⁷⁹ SSVEC asserts
 12 Staff's position does not consider that the process to reset the DSM adjustor can take as long as four
 13 or five months to approve, and that DSM program expenses that SSVEC incurred in the prior
 14 calendar year could not be recovered until the Commission acted. SSVEC is frustrated by the
 15 approval process because it is outside of the Cooperative's control, and in the past it has taken years
 16 to obtain approval to collect DSM program expenses.⁸⁰ SSVEC claims it is not in a financial position
 17 to "lay out" money for extended periods while it waits for Commission approval.⁸¹

18 In addition, SSVEC requests that there be language as part of this Order that would not
 19 preclude SSVEC from filing for a reset of its DSM adjustor more than once a year if the Cooperative
 20 deemed it necessary.⁸² Staff does not oppose this request.⁸³

21 We agree with Staff that the new DSM adjustor rate should not go into effect except by
 22 Commission Order. The DSM adjustor has a direct impact on customer bills, and to have the new

23 ⁷⁸ Ex A-18 at 6.

24 ⁷⁹ SSVEC Reply Brief at 25.

25 ⁸⁰ From the period 2001 through 2006, SSVEC submitted semi-annual DSM program expenses for Staff approval
 pursuant to the mechanism established in the last rate case. In that period, SSVEC submitted DSM program expenses
 totaling \$549,929; Staff did not approve \$502,414 of such expenses until July 8, 2009. See Tr at 564-566; and Ex. A-24
 and A-25. SSVEC submitted its 2007 and 2008 DSM expenses for Staff approval on a semi-annual basis, such expenses
 were not approved until Staff filed the Supplemental Testimony of Mr. Irvine with its Opening Brief in this matter. See
 Tr. at 566-567; and also Late-filed Supplemental Testimony of Mr. Irvine.

27 ⁸¹ SSVEC Opening Brief at 49.

28 ⁸² *Id.* at 50.

⁸³ Tr. at 581-2.

1 rate go into effect automatically would diminish the Commission's ability to implement rates. Staff's
2 recommendation on this issue is consistent with recent Commission policy and actions. Under such
3 procedures, the Cooperative is protected in that uncollected expenses associated with approved DSM
4 programs will be recovered in the DSM adjustor account and can be recovered through future rates.

5 We also believe that the Cooperative's request to be able to file for a change to its DSM
6 adjustor more than once a year if the Cooperative has a valid need is reasonable. Such authority
7 allows the Cooperative to react quickly to changing circumstances. However, the Cooperative should
8 be judicious in deciding when to make extra filings, as too frequent requests to reset the DSM
9 adjustor would increase costs and may cause customer confusion. Because the DSM adjustor is
10 based on a projected budget, the Cooperative should only need to make an additional filing if it needs
11 to implement a new program with substantial benefits, or additional funding is required for an
12 existing program that has demonstrated substantial system or societal benefits.

13 SSVEC agrees with Staff Recommendation No. 10 that new DSM programs be submitted to
14 the Commission for approval. SSVEC requests, however, that it be permitted to offer new DSM
15 programs to its members prior to Commission approval and report the related expenses as part of its
16 semi-annual reports. SSVEC acknowledges that if the new program is not subsequently approved by
17 the Commission, it would not be permitted to recover the expenses associated with that program. If
18 however, the new program is approved by the Commission, SSVEC would be able to recover the
19 associated expenses through the DSM adjustor, and have them trued-up to the date it started offering
20 the program. Staff agrees with SSVEC's position on new DSM programs.⁸⁴

21 We concur with the parties' position concerning new DSM programs. This understanding
22 will allow SSVEC to implement new, beneficial DSM programs in a timely fashion. Customer rates
23 would not be affected, unless and until the Commission approves the program and then also approves
24 a change to the DSM adjustor rate.

25 With respect to Recommendation No. 13, SSVEC agrees with Staff that DSM program
26 expenses that have not yet been fully recovered through the WPCA/WPFCA would remain in the
27

28 ⁸⁴ Staff Opening Brief at 10.

1 WPFC/WPFCA, and that 2007 and 2008 program expenses that were under review by Staff during
2 this proceeding for approval pursuant to Decision No. 58358 would also be recovered through the
3 WPFCA.⁸⁵ The parties agree that all 2009 approved DSM program expenses will be reported and be
4 potentially recoverable through the DSM adjustor.⁸⁶

5 New DSM Programs and 2007 and 2008 DSM expenses

6 SSVEC proposed DSM programs including an Energy Efficient Water Heater Rebate
7 program, a Commercial and Industrial Energy Efficiency Improvement Loan program, and Energy
8 Efficient New Home or Remodel Rebate program. Staff also reviewed and made recommendations
9 concerning SSVEC's DSM Expense Reports for 2007 and 2008.

10 With respect to the above, Staff recommends:

- 11 1. Approval of the Energy Efficient Water Heater Rebate program with certain
12 changes;
- 13 2. To be eligible for the rebate, the energy factor for the purchased water heaters must
14 be greater than the federal standard for new manufacture;
- 15 3. The water heater rebate should be set at \$100;
- 16 4. SSVEC operate the water heater program without providing incentives for tankless
17 water heaters at this time;
- 18 5. The Commercial and Industrial Energy Efficiency Improvement Loan program be
19 approved as a pilot-program for a period of 16 months, and that following the 12th
20 month of program operation, SSVEC make a filing detailing its experience with the
21 program and a recommendation regarding continuation of the program;
- 22 6. Loans made in the Industrial Energy Efficiency Improvement Loan program be
23 interest free;
- 24 7. The Energy Efficient Improvement Loan Program be interest-free in order to make
25 them more accessible to customers;
- 26 8. The proposed Energy Efficient New Home or Remodel Rebate program be denied;

27 ⁸⁵ On May 22, 2009, Staff issued a letter to the Cooperative approving \$416,383.11 of SSVEC's 2007 and 2008 DSM
28 Program expenses, which expenses will be recovered through SSVEC's WPCA/WPFCA.

⁸⁶ Staff Opening Brief at 11.

- 1 9. SSVEC discontinue offering any incentive related to the replacement of any heating
2 or cooling appliance using an energy source other than electricity with an electric
3 appliance in order to promote fuel switching.

4 Additionally, Staff recommends a DSM budget for SSVEC as follows⁸⁷:

5 Residential Programs

6 Residential Energy Management	\$50,000
7 Touchstone Energy Efficient Home Program	\$175,000
8 Energy Efficient Water Heater Rebates	\$25,000
9 Energy Efficient Heat Pump Rebate	\$20,000
10 Energy Efficient Improvement Loan Program	\$200,000

12 Commercial and Industrial Programs

13 Commercial and Industrial Energy Management	\$4,500
14 C and I Energy Efficient Improvement Loan Program	\$150,000
15 Energy Efficient Water Heater Rebates	See Above
16 Energy Efficient Heat Pump Rebate	See Above

18 Advertising Program

19 Advertising brochures	<u>\$ 80,000</u>
20 Total Annual DSM Budget	\$704,500

21 Based on the foregoing, Staff recommends the new DSM adjustor rate should be \$0.00088 per
22 kWh.⁸⁸ The DSM adjustor is calculated by dividing the budget of the approved projects by the

23 ⁸⁷ Staff Reply Brief at 6, Attachment 1.

24 ⁸⁸ SSVEC agreed with the recommendations in Mr. Irvine's Supplemental Testimony, except it had two concerns with
25 Staff's recommendation that the EEILP interest rate be lowered from 3 percent to 0 percent to make it more accessible to
26 customers. First, SSVEC was concerned that Staff's recommendation would result in increased costs to the Cooperative
27 that were not reflected in Staff's recommended DSM adjustor rate of \$0.000474 per kWh. Second, based on focus group
28 information, by lowering the interest rate, the Cooperative expects more customers will participate in the program, and it
would incur additional expenses more quickly. Consequently, SSVEC discussed the matter with Staff and requested that
to cover the costs of the C&ILP and EEILP, the adjustor rate be increased to \$0.00088 per kWh. With this agreement to
the DSM adjustor rate, the Cooperative states it agrees with all of Staff's recommendations set forth in the Supplemental
Testimony. Staff agrees with the \$0.00088 per kWh. See Staff Reply Brief Attachment 1.

1 projected kWh retail sales (\$704,500/799,860,156 kWh's=\$0.000881 per kWh). Staff calculates that
 2 for a residential customer on the Residential Service – Schedule R tariff with average monthly usage
 3 of 728 kWh, the initial DSM adjustor rate (\$0.00088 per kWh) would result in a monthly charge of
 4 \$0.64, or \$7.69 per year. According to Staff, a commercial customer on the General Service –
 5 Schedule GS tariff, using the monthly average of 483 kWh, would pay a monthly charge of \$0.43, or
 6 \$5.10 annually.⁸⁹

7 Staff's recommendations concerning SSVEC's DSM programs and the initial DSM adjustor
 8 are reasonable and we adopt them.

9 Wholesale Power and Fuel Cost Adjustor ("WPFCA")

10 The Wholesale Power and Fuel Cost Adjustor is a purchased power adjustor that uses charges
 11 or credits to allow the Cooperative to collect or refund the difference between the base cost and the
 12 actual cost of wholesale power. Currently, SSVEC has the authority to change the fuel adjustor rate
 13 without Commission approval. In this case, SSVEC proposed that it be allowed to adjust the
 14 WPFCA rate without Commission approval unless such adjustment would result in a cumulative
 15 annual increase in the total average rate collected from customers per kWh greater than 10 percent.⁹⁰
 16 SSVEC further requests that any increase submitted to the Commission for approval in excess of the
 17 10 percent limit would become effective in 60 days unless the Commission took action.⁹¹ SSVEC
 18 claims that its proposal would allow it to recover routine fluctuations in fuel costs in a timely manner,
 19 but the 10 percent limit would ensure that a significant increase would not be implemented unless
 20 approved by the Commission. The Cooperative also requests that the WPFCA include fuel costs that
 21 would arise from its own generating units.

22 Staff recommends that SSVEC be required to submit proposed increases to the WPFCA rate
 23 to the Commission for approval, but not be required to seek approval for decreases to its WPFCA
 24 rate.⁹² In addition, Staff recommends establishing thresholds that would trigger changes in the
 25 WPFCA for both under- and over- collected bank balances.⁹³ Staff recommends a \$2 million

26 ⁸⁹ Staff Reply Brief, Attachment 1.

27 ⁹⁰ Ex A-8 Hedrick Rebuttal at 19.

28 ⁹¹ *Id.*

⁹² Ex S-12 McNeely-Kirwin Direct at 7-8.

⁹³ *Id.*

1 threshold for under-collection and a \$1 million threshold for over-collection. Under Staff's
 2 recommendation, SSVEC would be required to file an application to increase the WPFCA rate either
 3 when the bank balance reaches the \$2 million threshold for under-collected balances for two
 4 consecutive months, or when it reasonably anticipates that the threshold will be reached within six
 5 months and would continue at or above the threshold for two or more consecutive months. Staff
 6 asserts that the threshold would limit the size of any negative bank balance that could accumulate,
 7 limit increases to the WPFCA, and limit rate shocks to customers. Under Staff's proposal, SSVEC
 8 could return over-collected bank balances to its customers at anytime, except that it must return over-
 9 collected amounts once the over-collected bank balance reaches \$1 million and remains over that
 10 threshold amount for two consecutive months. Staff states that this mechanism would ensure that
 11 positive bank balances are returned to customers in a timely and predictable fashion.⁹⁴ Staff does not
 12 appose the collection of fuel costs associated with future Cooperative owned generation plants.⁹⁵
 13 Staff recommends certain fuel expenses that should be included in the WPFCA.⁹⁶

14 SSVEC agrees with Staff's recommended threshold amounts.⁹⁷ SSVEC argues, however, that
 15 it should not have to seek Commission approval every time it determines it must increase the
 16 WPFCA. SSVEC does not believe that Staff's position takes into account that despite being a PRM,
 17 the Cooperative will obtain approximately 80 percent of its power needs from AEPCO, and that
 18 through 2012 it could obtain as much as between 75.3 and 88.3 percent of its power from AEPCO.
 19 SSVEC claims it cannot control the fuel costs that AEPCO passes through to its members in
 20 AEPCO's Commission-approved adjustor. SSVEC asserts that Staff's position will result in the
 21 Commission reviewing power costs twice because the majority of such costs will have been reviewed
 22 for AEPCO prior to the pass through to SSVEC.

23 SSVEC claims that having to file for any and all increases to its WPFCA would: (i)
 24 negatively impact its ability to administer its bank balance; (ii) require the Cooperative to use its net
 25 income to "lay out" the money to purchase the power for extended periods of time; (iii) require the

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 27 ⁹⁴ *Id.* at 9.

⁹⁵ Ex S-12 McNeely Kirwin Direct at 11.

⁹⁶ *Id.* At 11-12.

28 ⁹⁷ SSVEC Reply Brief at 17.

1 expenditure of time, money and resources for a Commission proceeding to implement even a small
 2 increase; (iv) cause significant delay in its ability to recover costs; and (v) hinder its ability to comply
 3 with the under-collection bank balance threshold. SSVEC asserts the agreed-upon thresholds for
 4 under- and over-collections will address Staff's concerns about rate shock. SSVEC believes that
 5 Staff's position is an over-reaction to an anomalous situation in 2008 when fuel prices were
 6 especially volatile during SSVEC's first year of operations as a PRM.

7 SSVEC argues further that if the Commission requires SSVEC to file for increases in the
 8 WPFCA, the agreed-upon WPFCA rate should be considered an initial ceiling for adjustment
 9 purposes. Under this proposal, if the WPFAC rate is lowered such that it is below the initial rate,
 10 then SSVEC would not need to seek Commission approval to raise the rate back to the original
 11 level.⁹⁸ Staff opposes this proposal.⁹⁹

12 Alternatively, SSVEC proposes that if the Commission requires the Cooperative to file for an
 13 increase in its WPFCA, the increase should go into effect if the Commission does not act upon the
 14 filing within 60 days.¹⁰⁰ SSVEC notes that Staff admits that it can take as long as four or five months
 15 for the Commission to approve an adjuster reset.¹⁰¹ Moreover, SSVEC claims, the Commission has
 16 approved adjusters for AEPCO,¹⁰² Arizona Public Service¹⁰³ and UNS Electric¹⁰⁴ that go into effect
 17 unless suspended by the Commission. SSVEC requests to be treated in the same manner in the event
 18 the Commission requires it to seek approval of all WPFCA increases. In addition, SSVEC requests
 19 that if the Commission requires it to seek approval for all WPFCA increases, that power purchased
 20 from AEPCO that is passed through the Commission-approved AEPCO adjuster should not be
 21 considered for purposes of an increase to the WPFCA.¹⁰⁵

22 On May 22, 2009, Staff issued a letter to the Cooperative approving \$416,383.11 of SSVEC's
 23 2007 and 2008 DSM Program expenses, which expenses will be recovered through SSVEC's
 24

25 ⁹⁸ SSVEC Opening Brief at 36.

26 ⁹⁹ Tr. at 610-11.

27 ¹⁰⁰ SSVEC Opening Brief at 57-8.

28 ¹⁰¹ Tr. at 539.

¹⁰² Decision No. 68071 (August 17, 2005).

¹⁰³ Decision No. 69639 (June 11, 2007).

¹⁰⁴ Decision No. 70360 (May 27, 2008).

¹⁰⁵ SSVEC Opening Brief at 39.

1 WPFCA. SSVEC requests that these costs associated with 2007 and 2008 DSM programs should be
2 excluded for purposes of increases in the WPFCA and the \$2 million under-recovery threshold. Staff
3 opposes such treatment.¹⁰⁶ SSVEC argues Staff's position makes no practical sense because the
4 DSM costs at issue were already expended and once recovered will be gone. SSVEC states that an
5 additional "\$416,383.11" in the adjustor bank balance will not cause rate shock and its inclusion is a
6 temporary clean-up from the 1993 Rate Decision.

7 Staff argues that requiring Commission approval of any increase in the WPFCA rate would
8 allow the Commission to ensure that SSVEC is requesting an appropriate WPFCA rate and that
9 supporting projections are reasonable. Staff argues further that requiring Commission approval
10 allows the Commission to assist in designing cost recovery to limit rate shocks by instituting
11 graduated increases and limiting increases during the peak-usage months.¹⁰⁷ Staff believes that
12 SSVEC's recent conversion from an ARM to a PRM has caused its energy costs to be more volatile,
13 which has impacted the WPFCA rate. Staff argues that the Commission's rate making authority and
14 obligation to set fair, just and reasonable rates includes the ways in which purchased power or fuel
15 costs are passed on the customers.

16 Staff opposes the Cooperative's proposal for automatic adjustment because there is no way to
17 determine what the impact would be on customer bills, and because Staff believes the proposal is
18 unduly complex and difficult to track for compliance reasons. Furthermore, Staff asserts that the
19 complexity of the proposal makes it unlikely to be transparent to ratepayers.¹⁰⁸ Staff states that the
20 testimony at the hearing illustrates the complexity and ambiguity in SSVEC's proposal, as it is not
21 clear whether SSVEC's proposal is premised on a 10 percent change in fuel costs, as suggested in
22 written testimony, or whether it is based on a 10 percent change in the total customer bills, as it
23 appears in verbal testimony.¹⁰⁹

24 Staff asserts that SSVEC's argument that requiring Commission approval of the WPFCA will
25 result in double review of the AEPCO portion of the fuel costs is not persuasive. Staff claims that if
26

106 Tr. at 608-09.

107 Ex S-13 McNeely-Kirwin Surrebuttal at 2.

108 Tr. at 598.

109 Tr. at 256-57 and 663.

1 the AEPCO portion of the WPFCA has already been reviewed by Staff and approved, Staff would
2 take notice of that fact in reviewing that component of the SSVEC WPFCA rather than "re-invent the
3 wheel."¹¹⁰

4 Staff asserts that SSVEC's request that in the event the Commission orders that it file for an
5 increase to its WPCA, that the increase should go into effect automatically if the Commission does
6 not act on the request within 60 days, is also inappropriate because it would prevent the Commission
7 from evaluating and considering the circumstances leading to the request.¹¹¹ Staff states that SSVEC
8 has failed to demonstrate why a 60-day turnaround time is necessary or why the longer turnaround
9 time is more than an inconvenience rather than a hardship.¹¹²

10 We agree with Staff's recommendation that SSVEC must apply for approval of any increase
11 to its WPFAC rate. We do not find it in the public interest to allow increases in the WPFAC rate
12 without Commission approval at this time. Neither are we convinced that the rate should be allowed
13 to increase if the Commission does not act within 60 days. The Commission has limited resources
14 and cannot determine in advance the demands that will be placed on those resources. The potential
15 impact on rates is significant and it is not in the public interest for the Commission to abdicate its
16 authority over rates. We believe that if it is true that the primary component of the WPFCA will be
17 attributable to fuel costs passed through by AEPCO in its adjustor, Staff's review of any SSVEC
18 application will be made all the easier and SSVEC should not experience long delays. We do not
19 find the Cooperative's proposed limits on the automatic adjustment to be easily understood or tracked
20 and believe that would create confusion for compliance and among ratepayers.

21 We concur with the parties that the WPFCA may include fuel costs associated with future
22 Cooperative owned generation units, but make no conclusions at this juncture about the prudence of
23 these potential future costs. We also adopt Staff's recommendations as set forth in the direct
24 testimony of Ms. McNeely-Kirwin concerning the costs that are appropriately included in the
25 WPFAC.

26 We agree with the Cooperative that the \$416,383.11 of DSM costs for 2007 and 2008 that are

27 ¹¹⁰ Staff Reply Brief at 6.

28 ¹¹¹ *Id.*

¹¹² *Id.*

1 being collected as part of the WPFAC should not be included in the under-collected balance for
2 purposes of determining if SSVEC has reached the \$2 million threshold for filing a request to
3 increase the WPFAC. These DSM costs are a finite sum and have already been incurred. Once
4 collected they will not re-accrue. There is no reason for ratepayers to pay increased rates on account
5 of these 2007 and 2008 DSM expenditures.

6 Power Procurement

7 By changing from an All Requirements Member ("ARM") to a PRM, SSVEC is responsible
8 for procuring wholesale power needed to supplement the power that it obtains from AEPCO. SSVEC
9 has estimated that it will receive approximately 80 percent of its power from AEPCO and 20 percent
10 from other sources.¹¹³

11 Staff believes that since becoming a PRM, SSVEC has substantially increased its
12 responsibility for ensuring reliable and economic service to its customers, including planning for
13 power supplies, power purchases, identifying and evaluating power supply alternatives, selecting its
14 preferred power suppliers, and implementing management's decisions. Staff notes that although
15 SSVEC states it expects to obtain only 20 percent of its power needs from sources other than
16 AEPCO, it is only required to purchase approximately 47 percent of its wholesale power from
17 AEPCO.¹¹⁴ Thus, Staff believes SSVEC's power procurement policies and performance could have a
18 substantial effect on its costs. Staff agrees with SSVEC that 2008 was an anomalous year, not just
19 because power prices were unusually volatile, but because SSVEC was developing more expertise
20 operating as a PRM.

21 Because of SSVEC's new PRM status, Staff recommends that SSVEC develop more formal
22 written procurement policies and procedures. Staff did not recommend that SSVEC adopt specific
23 procedures concerning power procurement, but rather Staff developed criteria that it believes SSVEC
24 should consider when developing written procurement policies. Staff believes the policies and
25 procedures will provide guidance to, and a benchmark for, measuring the performance of those
26 responsible for procuring power. Staff believes that top-level management should adopt the

27 ¹¹³ Ex A-5 Brian Rebuttal at 3.

28 ¹¹⁴ Tr. at 172-73.

1 procedures to ensure the policies are given high priority. Staff states further that SSVEC needs to
2 create a mechanism that allows it to systematically evaluate progress and results, by allowing SSVEC
3 to compare its chosen procurement options with available alternatives.¹¹⁵ In addition, Staff
4 recommends the written procedures include a provision that allows SSVEC to update them, in order
5 to have flexibility when conditions warrant.¹¹⁶

6 In addition, Staff recommends a prudence review of SSVEC's purchased power procurement
7 process in the next rate case or three years, whichever is first. Staff explains the timing is designed to
8 give SSVEC time to fully develop and implement its written purchase procurement policies.¹¹⁷

9 SSVEC argues there is a difference between a for-profit and a non-profit entity with regard to
10 power purchases. SSVEC states that SSVEC's management and Board of Directors are evaluated, in
11 part, based on their decisions with regard to power purchasing, and if its costs are too high, the
12 cooperative's membership can overturn the Board, or the Board could change management. SSVEC
13 argues that unlike an investor-owned utility, with a cooperative, it is the owner/members who are
14 paying the fuel costs, while with an investor-owned utility, the owners do not pay the costs of power.
15 According to SSVEC, the conflict between outside owners and ratepayers in the investor-owned
16 model is the fundamental basis for regulation and for prudence reviews. SSVEC argues the natural
17 incentive to keep rates low in a cooperative makes the prudence review unnecessary. SSVEC asserts
18 that the Commission already monitors SSVEC's cost of power when SSVEC files monthly reports,
19 and has the ability to review and evaluate SSVEC's power procurement activities, and can at any
20 time request more information from SSVEC to further evaluate SSVEC's activities.

21 Furthermore, SSVEC notes that as a cooperative, any costs found to be imprudent as part of a
22 prudence review cannot be charged to anyone other than the member ratepayers, as there are no
23 shareholders to bear the brunt of such costs. SSVEC argues that it always endeavors to avoid
24 imprudent costs, and the existence of a requirement to undergo a future prudence review will not alter
25 its activities to procure power at the lowest possible cost. SSVEC believes that imposing the
26 requirement of a prudency review would cause SSVEC to devote additional and significant time,

27 ¹¹⁵ Tr. at 119.

28 ¹¹⁶ *Id.*

¹¹⁷ Ex S-3 Mendl Surrebuttal at 2.

1 limited resources, and expense, and is an over-reaction to the unique circumstances that arose in
2 2008.

3 Staff, however, believes that SSVEC takes a too narrow view of the function and value of a
4 prudence review. Staff does not believe that SSVEC's status as a nonprofit is relevant, because the
5 effect of higher than necessary fuel costs on customers is the same despite its non-profit cooperative
6 structure. Staff states that a prudence review would simply improve the power procurement process
7 to make it more transparent.¹¹⁸

8 Staff does not believe the monthly filings or the best practices obligations for fuel purchases
9 provide the same safeguards as a prudence review. Staff states it has found that in some instances
10 the monthly filings are inaccurate and need to be corrected. Staff does not believe that they create a
11 complete picture that a prudence review would provide. According to Staff, the best practices for
12 fuel procurement only apply to longer term contracts, while a prudence review would focus on the
13 internal processes to determine how much to bid, when to bid, and the specific types of products
14 being sought.

15 A prudence review does more than determine how fuel procurement costs should be allocated
16 between owners and ratepayers. It can help determine the effectiveness of SSVEC's procurement
17 policies and how well its management is able to operate under these policies. The information about
18 management's effectiveness, or the tools to evaluate management with respect to fuel procurement
19 may not be readily available to cooperative members, and consequently, members may not be able to
20 make well-informed decisions concerning management's effectiveness in this area. On the other
21 hand, if a review indicates that fuel procurement has not been prudent, there are no shareholders to be
22 charged with the imprudently incurred costs. We do not have to decide now whether a fuel
23 procurement prudency review should be required in three years or in the next rate case. We believe it
24 is better to allow Staff to determine in the next rate case, based on intervening facts, how best to
25 investigate SSVEC's fuel procurement policies and practices. This may result in a full prudency
26 review, or it may involve a lesser investigation. Now that SSVEC is a PRM, such review is

27
28 ¹¹⁸ Tr. at 123.

1 appropriate and could either validate management's performance or result in recommendations to
2 improve the process. By not mandating a full-blown prudency review now, we avoid committing
3 Commission and Cooperative resources to a potentially expensive undertaking even if in the future,
4 SSVEC ends up taking the vast majority of its power from AEPCO, or it is otherwise apparent that a
5 prudency review is not necessary or unlikely to be helpful. SSVEC will be filing for changes to its
6 WPFCA as well as other reports, and Staff will be able to monitor how the Cooperative's fuel
7 purchases are affecting rates and can request additional information from SSVEC or conduct a
8 prudency review sooner than the next rate case if it appears that SSVEC is not acting prudently with
9 respect to fuel purchases. SSVEC has agreed to file written procurement policies as Staff
10 recommended.

11 **Tariff Changes and Service Conditions and Miscellaneous**

12 The parties have agreed to SSVEC's proposed Service Conditions proposed in the
13 Application as modified by Staff, and as set forth in Exhibit A-16 in this proceeding. These changes
14 include the elimination of the construction allowance for line extensions. There was no opposition
15 expressed in the proceeding to the elimination of the construction credit for line extensions. We note
16 that the elimination of the credit is consistent with actions taken in connection with other utilities and
17 with the concept that current ratepayers should not have to subsidize growth.

18 Additionally, SSVEC should submit for Commission approval revised line extension policies
19 which reflect:

- 20 • A Schedule of Charges
- 21 • A statement that quotes provided to customers will be itemized
- 22 • Procedures for refunding amounts to customers when additional customers connect to
23 the line extension.

24 With the exception of customer charges and the two service related fees, as discussed herein,
25 SSVEC has agreed to Staff's revenue allocation and rate design, including Staff's recommended
26 time-of use rates.¹¹⁹

27
28 ¹¹⁹ SSVEC Opening Brief at 10.

Staff has accepted SSVEC's proposed tariff changes, and SSVEC has agreed that in a future rate case filing, it will develop more detailed and conventional unbundled rates, which will not result in any incentive or disincentive for customers who want to choose competitive generation supplies.¹²⁰

SSVEC has agreed with Staff's recommendation that within 30 days of a Decision in this matter, SSVEC will file with the Commission a tariff describing its bill estimation methodologies.¹²¹

Sonoita Reliability Project

The Sonoita area is currently served by a 360-mile three-phase feeder line. SSVEC presented evidence that the Sonoita area is plagued by more outages than other areas in its service territory.¹²² SSVEC states that it has been working hard toward a solution to bring quality, reliable power to the Sonoita/Elgin/Patagonia communities. After years of study and analysis, the Cooperative states that it identified that the best solution to the problem is a new substation in Sonoita, with four shorter feeders and upgrading the transmission to 69 kV (the "Project"). SSVEC claims that it considered community input in its decision and that its proposed route balances basic aspects of business practices and cost analysis. SSVEC determined that the final route should follow the existing easement along the San Ignacio Del Babocamri Land Grant ("SIDB"). According to SSVEC, the SIDB easement and affiliated easements to the original substation property have been on record for over 25 years.¹²³

The evidence presented in the hearing indicates that the Sonoita area has had a 10-year average of 270 hours of outages per year because of the unreliability of the existing line. Mr. Huber testified for the Cooperative that he believed the community would continue to be plagued by outages if SSVEC does not move forward soon with the Project. He expressed concerns for the elderly and for businesses in the area. Mr. Huber testified that investing in renewable energy in the local area will not solve the problem as the problem is one of capacity and reliability. He also testified that the 69 kV line is not the reason the Cooperative filed the rate case.¹²⁴

SSVEC believes that the option it chose for the 69 kV line is the only viable option, and it

¹²⁰ Ex S-8 Musgrove Direct at Executive Summary, ¶ 2; Ex A-8, Hedrick Rebuttal at 1-2.

¹²¹ Ex S-8 Musgrove Direct at 12-13; Ex A-8 at 1-2.

¹²² Tr. at 70, Ex A-4.

¹²³ *Id.*

¹²⁴ Tr. at 70-71; 90 - 108; Ex A-4.

1 claims that it will do everything that it can to mitigate the impacts. SSVEC notes that the
 2 Commission does not have jurisdiction over the siting of this line pursuant to A.R.S. §40-360, et
 3 seq.¹²⁵ SSVEC claims that further delay in the Project will increase its cost and prolong the risk of
 4 outages in the area. SSVEC believes that further delay could lead to the imposition of a moratorium
 5 on new hookups in the area as the existing line is at capacity.

6 Staff reviewed the Project. SSVEC notes that Staff testified that (1) SSVEC has evaluated
 7 numerous options for the Project and the Project will improve reliability in the affected area; (ii)
 8 SSVEC has communicated with its members in the area in an attempt to clarify that the primary issue
 9 related to the Project is reliability and the quality of service; and (iii) SSVEC should continue to
 10 upgrade its 69 kV sub-transmission and distribution system to improve system performance and
 11 reliability.¹²⁶

12 Members from the Sonoita/Elgin/Patagonia area want the Cooperative to consider whether
 13 renewable distributed generation located in the area would eliminate the need for the new line. Some
 14 of the commenters in opposition to the line do not believe that the Cooperative has studied all
 15 reasonable alternatives.¹²⁷ They complain the Cooperative did not provide them with sufficient detail
 16 of the cost estimates to allow evaluation of the Cooperative's claims about the project. They dispute
 17 Cooperative claims that the existing line is at capacity. Some suggest the Cooperative should work
 18 with the community to reduce consumption especially during peak load, or that the Cooperative
 19 should double circuit the existing line. They question the Cooperative's projections on growth and
 20 future demand, claiming they are inflated, and that official growth projections predict growth less
 21 than 2.3 percent per year (282 people) for the next five years, and they argue that the addition of a 1
 22 MW renewable energy plant every five years would cover increasing demand.¹²⁸

23
 24 ¹²⁵ SSVEC Opening Brief at 54.

¹²⁶ Ex S-5 Bahl Direct at 7; 19 and 20.

25 ¹²⁷ E.g. see comments of Jeanne Horseman, filed May 6, 2009. See also comments of Gail Gertzwiller docketed
 26 December 8, and December 31, 2008. On January 15, 2009 a Petition seeking an alternative route for the 69 kV line
 27 signed by 60 individuals was docketed. The Commission received at least 20 written comments concerning the Sonoita
 Reliability Project, and six comments opposing the rate increase and one in favor of the increase. Over 30 additional
 individuals appeared at the February 11, 2009 Public Comment meeting in Sierra Vista, many to speak about the Sonoita
 Line, but others speaking about SSVEC's importance to the community or about the effect of higher rates. For additional
 Public Comment, see also Transcript of the April 21, 2009 hearing at 7-42.

28 ¹²⁸ Horseman Comments at 4.

1 The Cooperative estimates that the Sonoita Reliability Project will cost \$13.5 million, and that
 2 the cost will increase over time.¹²⁹ The current estimate is higher than the cost originally provided to
 3 members because the project has been modified to require a slightly longer line and because costs
 4 have increased with the passage of time.¹³⁰ Members in the local community have argued that having
 5 additional distributed generation in the local area would alleviate the need for the line upgrade. The
 6 Cooperative asserts, however, that the problem is one of capacity, and even with additional local
 7 generation, the line would need to be upgraded in order for the power to reach users.¹³¹ The
 8 Cooperative asserts that because the existing line is at capacity, and at times exceeds capacity, the
 9 area is subject to blinking during periods of high demand.¹³² The Cooperative claims that it receives
 10 numerous complaints from residents and businesses in the area about the blackouts, and suggests that
 11 these interests have been patient for a long time while the Cooperative works on a solution.¹³³
 12 SSVEC states that breaking the line into smaller feeders will help reliability because a problem on
 13 one portion of the line will not affect the entire area.¹³⁴

14 The evidence indicates that the planned upgrade of the existing 360 mile three phase feeder to
 15 a 69 kV line, with a new substation and four smaller feeders, will address the capacity issues and
 16 improve system reliability in the Sonoita area. The upgrade will not prevent local efforts to install
 17 renewable generation sources, but would enable the generation to be utilized by providing a
 18 transmission path.

19 The Commission's Line Siting Committee does not have jurisdiction over the siting of the
 20 proposed 69 kV line,¹³⁵ and the Commission does not design utility infrastructure. However, the
 21 Commission does have authority to ensure that the Cooperative is providing safe and reliable service.
 22 The Cooperative is responsible for designing and operating a safe and reliable system for all of its
 23 members. The Cooperative submitted evidence that the line is currently at capacity.

24 To allow substandard service is not in the public interest. SSVEC's management believes that

25 ¹²⁹ Tr. at 101-03.

26 ¹³⁰ Tr. at 103.

27 ¹³¹ Tr. at 98.

28 ¹³² Tr. at 92-93.

¹³³ Tr. at 302-303.

¹³⁴ Tr. at 93.

¹³⁵ A.R.S. §40-360 et al.

1 the Sonoita Reliability Project is required for it to provide safe and reliable service to the Sonoita
2 area. Ultimately, the Cooperative is responsible for the quality of service for all of its members, and
3 must make informed decisions on how to meet its obligation. The information presented in the course
4 of this proceeding supports the Cooperative's position. The Cooperative has explored alternative
5 configurations for the project and has selected the project as presented as the best balance between
6 cost and impact on the community. Staff testified that the Project would improve reliability in the
7 area.

8 However, we are concerned that once constructed, the project will permanently change the
9 landscape for the impacted communities and the manner in which electric service is provided to the
10 Cooperative's customers. We need to ensure that the goals of some in the local communities who
11 want more investment in renewable generation to mitigate the need for the project have been fully
12 considered by the Cooperative. We believe a feasibility study prepared on behalf of the Cooperative
13 by an independent third party is necessary for further analysis and consideration of the issues
14 presented, prior to proceeding with construction of the project. Therefore, we shall require the
15 Cooperative to docket a feasibility study on the project and possible alternatives and hold public
16 forums in the impacted communities. The public forums shall include an opportunity for community
17 members' discussion on the feasibility study, including alternatives prior to construction of the
18 project. At the conclusion of the public forums the Cooperative shall docket a report and minutes
19 from the public forums.

20 We will require the Cooperative to file a report setting out a proposed plan for the public
21 forums including the manner it intends to provide notice and the dates and times as well as topics to
22 be addressed at the public forums. The topics shall include, but not be limited to, addressing how
23 renewable energy generation (in particular distributed generation) could be incorporated into the
24 generation plans to serve the area covered by the planned 69kV line and associated upgrades. We
25 will also require SSVEC to file, by July 31, 2010, a report discussing the outcome of this public
26 process and also discussing how the Cooperative plans to incorporate the reasonable and effective
27 renewable energy proposals resulting from the public forums.

28

* * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On June 30, 2008, SSVEC filed with the Commission an application for a rate increase.

2. On July 18, 2008, SSVEC filed Revisions to its Application.

3. On July 30, 2008, Staff notified the Cooperative that its application was sufficient under the requirements outlined in A.A.C. R14-2-103, and classified the Cooperative as a Class A utility.

4. By Procedural Order dated August 18, 2008, a procedural schedule was established and the matter was set for hearing to commence on April 21, 2009.

5. On November 12, 2008, SSVEC filed a Notice of Filing Affidavits of Mailing and Publication, indicating that Public Notice of the Hearing was mailed to its members/customers between September 26, 2008, and October 24, 2008, and was published in the *Sierra Vista Herald/Bisbee Daily Review* on October 16, 2008, and in the *Weekly Bulletin*, the *San Pedro Valley News-Sun*, and the *Arizona Range News* on October 15, 2008.

6. On January 6, 2009, Staff filed a Request for Extension of Time to File the Direct Testimony of Jerry Mendl concerning purchased power procurement. SSVEC did not object, and the schedule for filing testimony was revised by Procedural Order dated January 6, 2009.

7. In response to comments received from customers, the Commission determined that there was sufficient interest in the rate case and the potentially related matter of a new 69 kV transmission line in the Sonoita area that a Public Comment meeting in the local community was warranted. By Procedural Order dated February 5, 2009, the Commission scheduled a Public Comment meeting to be held in Sierra Vista, Arizona on February 11, 2009.

8. On February 10, 2009, SSVEC filed Notice of Compliance with Publication and Notice of the February 11, 2009, Public Comment Meeting. SSVEC made arrangements for the *Sierra Vista Herald/Bisbee Daily Review*, the *Weekly Bulletin*, the *San Pedro Valley News-Sun*, and

1 the *Arizona Range News* to publish Notice of the Public Comment prior to February 11, 2009, and
2 posted the Notice in the Community Events section of its website as well as in all SSVEC offices and
3 operations facilities open to the public, and delivered copies to the Willcox library, post office and
4 City Hall. Additionally, SSVEC stated an article discussing the Public Comment meeting appeared
5 in the February 6, 2009, *Sierra Vista Herald*.

6 9. On February 11, 2009, the Commission held a Public Comment meeting in Sierra
7 Vista.

8 10. On March 12, 2009, Staff filed a Motion for Extension of Time to File Surrebuttal
9 Testimony of William Musgrove concerning rate design.

10 11. On March 18, 2009, SSVEC filed a Response to Staff's Motion. SSVEC did not
11 oppose the request but sought assurances that other witnesses' testimony would be filed as scheduled
12 and Staff would attempt to provide an electronic version of Mr. Musgrove's testimony when ready.

13 12. By Procedural Order dated March 19, 2009, Staff's Motion was granted.

14 13. The hearing convened as scheduled before a duly authorized Administrative Law
15 Judge on April 21, 2009, at the Commission's offices in Tucson, Arizona, and continued through
16 April 23, 2009. Creden Huber, David Hedrick, David Brian and John Blair testified for SSVEC.
17 Jerry Mendl, William Musgrove, Crystal Brown, Julie McNeely-Kirwn and Steve Irvine testified for
18 Staff. The parties stipulated to the admission of the pre-filed testimony of Rebecca Payne for the
19 Cooperative and Prem Bahl for Staff.

20 14. SSVEC and Staff filed Opening Briefs on May 22, 2009, and Reply Briefs on June 9,
21 2009. Attached to Staff's Opening Brief was the Supplemental Testimony of Steve Irvine concerning
22 Staff's review and recommendations on SSVEC's proposed new DSM programs.

23 15. On April 23, 2009, Commissioner Stump filed a letter in the docket requesting
24 information from the Cooperative about the impact of the elimination of the credit of \$1,740 for
25 residential line extensions.

26 16. On April 24, 2009, Commissioner Newman filed a letter in the docket requested
27 additional information about the Line Extension Policy.

28 17. On May 13, 2009, SSVEC filed Responses to Commissioner Stump and

1 Commissioner Newman.

2 18. On June 16, 2009, Staff filed Responses to Commissioner Stump and Commissioner
3 Newman.

4 19. SSVEC is an Arizona member-owned non-profit rural electric distribution cooperative
5 headquartered in Willcox, Arizona. The Cooperative is a Class A public service corporation that
6 provides electric distribution service to approximately 51,000 members/customers located in most of
7 Cochise County and portions of Santa Cruz, Pima and Graham Counties.

8 20. SSVEC is a Class A member of AEPCO, a generation cooperative.

9 21. On January 1, 2008, SSVEC converted its membership in AEPCO from an All
10 Requirements Member to a Partial Requirements Member pursuant to Commission Decision No.
11 70105 (December 21, 2007).

12 22. The Cooperative's current rates were established in Decision No. 58358 (July 23,
13 1993).

14 23. As discussed herein, SSVEC's FVRB is determined to be \$132,866,202, which is the
15 same as its OCRB.

16 24. In the Test Year ended December 31, 2007, SSVEC had adjusted total revenues of
17 \$92,825,281.

18 25. As discussed herein, we find that in the Test Year, SSVEC's allowable Operating
19 Expenses total \$85,105,081, resulting in Operating Income of \$7,720,200, a 5.81 percent return on
20 FVRB, a Net Income of \$1,281,605, a TIER of 1.17 and DSC of 1.41.

21 26. SSVEC sought a revenue increase of \$9,862,959, or 10.63 percent, from \$92,825,281
22 to \$102,688,240. Based on our allowed Test Year Expenses, the Cooperative's proposal would
23 produce Operating Income of \$17,583,159, for a 13.23 percent rate of return on FVRB, and yield Net
24 Income of \$11,144,564, an operating TIER of 2.67, and DSC of 2.32.

25 27. The Cooperative based its requested increase primarily on a goal to increase its equity
26 to 30 percent of total capital by approximately 2016, and to meet the TIER and DSC requirements of
27 its lender.

28 28. Staff recommended a revenue increase of \$7,595,316, or 8.18 percent, from

1 \$92,825,281 to \$100,420,597. Staff's recommendation would produce Operating Income of
2 \$15,365,515, for an 11.56 percent rate of return on FVRB, yield Net Income of \$8,926,940, a TIER
3 of 2.34 and DSC of 2.12.

4 29. At the end of 2008, SSVEC's equity was 25.2 percent of total capitalization and was
5 projected to fall to approximately 23 percent of total capitalization in 2009.¹³⁶

6 30. The goal of increasing SSVEC's equity to 30 percent of total capitalization by
7 approximately 2016 is reasonable.

8 31. The evidence supports the Staff's projection for equity growth.

9 32. Total revenues of \$100,430,597 will allow the Cooperative to meet its lender's
10 required financial ratios and achieve a 30 percent equity ratio in a reasonable period of time. This
11 revenue level is an increase of \$7,605,316 or 8.19 percent, over Test Year revenues; resulting in an
12 11.53 percent return on FVRB, which is reasonable under the circumstances of this case.

13 33. It is reasonable that until the Cooperative reaches total equity level of at least 30
14 percent of total capitalization, that it should not return capital credits greater than 25 percent of its
15 Net Income in any year. Furthermore, until its next rate case, on May 1st of each year, the
16 Cooperative should file an annual update of its equity projections, which should include an
17 explanation of all assumptions and any deviations from the prior year's projections.

18 34. The Staff's proposed increase to customer charges is reasonable, and should be
19 adopted.

20 35. The Staff's proposed Service Charges are reasonable and should be adopted.

21 36. It is reasonable to establish the base cost of power for SSVEC at \$0.072127 per kWh.

22 37. Based on the revenue requirement approved herein, the average residential customer
23 with usage of 728 kWh per month, would see a monthly increase of approximately \$8.00, or
24 approximately 9.0 percent, from \$88.78 to approximately \$96.82.

25 38. Staff's recommendations concerning DSM projects, the DSM adjustor and the REST
26 as set forth herein and in the testimony of Steve Irvine are reasonable, and should be adopted.

27

28 ¹³⁶ Ex A-27.

39. It is fair and reasonable to set the initial DSM adjustor at \$0.00088 per kWh.

40. Based on usage of 728 kWh per month, the average residential customer would see a charge of \$0.64 per month attributable to DSM programs.

41. Staff's recommendations concerning the WPFCA as discussed herein are reasonable and should be adopted, except that DSM costs for 2008 and any prior years that are included in the WPFCA should not count toward the under-collected bank balance for determining when SSVEC must file for an increase in the WPFCA.

42. It is appropriate that future modifications to DSM programs and adjustments to the DSM adjustor shall be addressed by a future application in a separate docket, and SSVEC may make more than one application to re-set its DSM adjustor if the Cooperative believes it is necessary for the timely recovery of DSM program expenses.

43. It is reasonable that SSVEC be required to implement fuel procurement policies and to file its policies with Docket Control as a compliance item in this docket within a year of this Decision.

44. It is reasonable to defer a determination whether a fuel procurement prudency review is reasonable and necessary under the circumstances existing at the time of SSVEC's next rate case, taking into account the cooperative ownership structure.

45. SSVEC's proposed Service Conditions, as modified by Staff, and as set forth in Exhibit A-16 to this proceeding, are reasonable and should be adopted.

46. Staff's recommended TOU rate design (which does not include on-peak hours on weekends), is reasonable.

47. It is reasonable that in its next rate case filing, SSVEC shall file more detailed and conventional unbundled rates, which will not result in any incentive or disincentive for customers who want to choose competitive generation supplies.

48. Staff's recommendation that within 30 days of a Decision in this matter, SSVEC shall file with the Commission a tariff describing its bill estimation methodologies is reasonable.

CONCLUSIONS OF LAW

1. SSVEC is a public service corporation pursuant to Article XV of the Arizona

1 Constitution and A.R.S. §§ 40-250 and 40-251.

2 2. The Commission has jurisdiction over SSVEC and the subject matter of the
3 application.

4 3. Notice of the proceeding was provided in conformance with law.

5 4. The rates, charges, approvals and conditions of service approved herein are just and
6 reasonable and in the public interest.

7 5. It is in the public interest to approve SSVEC's DSM programs as conditioned by
8 Staff's recommendations in the Supplemental Testimony of Steven Irvine.

9 **ORDER**

10 IT IS THEREFORE ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. is
11 hereby authorized and directed to file with the Commission, on or before August 31, 2009, revised
12 schedules of rates and charges consistent with the discussion herein and a proof of revenues showing
13 that, based on the adjusted test year level of sales, the revised rates will produce no more than the
14 authorized increase in gross revenues.

15 IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective
16 for all service rendered on and after September 1, 2009.

17 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall
18 notify its customers of the revised schedules of rates and charges authorized herein by means of an
19 insert, in a form acceptable to Staff, included in its next regularly scheduled billing.

20 IT IS FURTHER ORDERED that as long as its equity capital is less than 30 percent of total
21 capitalization, Sulphur Springs Valley Electric Cooperative, Inc. shall not return any capital credits
22 that total more than 25 percent of its Net Income/Net Margin in any given year.

23 IT IS FURTHER ORDERED that until its next rate case, on May 1 of each year, Sulphur
24 Springs Valley Electric Cooperative, Inc. shall file an update of its equity projections, which report
25 should include an explanation of all assumptions and any deviation from the prior year's projections.

26 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall
27 recover the costs of Commission-approved DSM programs through a DSM Adjustment Tariff as
28 recommended by Staff in this proceeding.

1 IT IS FURTHER ORDERED that Commission-approved DSM costs should be assessed to all
2 Sulphur Springs Valley Electric Cooperative, Inc. electric customers as a clearly labeled single line
3 item per kWh charge on the customer bills.

4 IT IS FURTHER ORDERED that future modifications to DSM programs and adjustments to
5 the DSM adjustor shall be addressed by a future application in a separate docket, and Sulphur Springs
6 Valley Electric Cooperative, Inc. may make more than one application to re-set its DSM adjustor if
7 the Cooperative believes it is necessary for the timely recovery of DSM program expenses

8 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall file
9 its report on DSM program expenses semi-annually on March 1, for the period July through
10 December, and September 1, for the period January through June.

11 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall file
12 the DSM program expense reports in Docket Control and shall redact any personal customer
13 information, and that the DSM program expense reports shall include the following: (i) the number
14 of measures installed/homes built/participation levels; (ii) copies of marketing materials; (iii)
15 estimated cost savings to participants; (iv) gas and electric savings as determined by the monitoring
16 and evaluation process; (v) estimated environmental savings; (vi) the total amount of the program
17 budget spent during the previous six months and, in the end of year report, during the calendar year;
18 (vii) the amount spent since the inception of the program; (viii) any significant impacts on program
19 cost-effectiveness; (ix) descriptions of any problems and proposed solutions, including movements of
20 funding from one program to another; and (x) any major changes, including termination of the
21 program.

22 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. should
23 file its new proposed DSM adjustor rate with Docket Control by March 1st of each year, and that such
24 filing be considered and adjudicated by the Commission in Open Meeting.

25 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc.'s DSM
26 adjustor rate shall be reset by Commission Order annually on June 1 of each year, and that the per
27 kWh rate shall be based upon currently projected DSM costs for that year (the year for which the
28 calculation is being made) adjusted by the previous year's over- or under-collection, divided by

1 projected retail sales (kWh) for that same year.

2 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc.'s new
3 DSM adjustor rate shall become effective as directed by Commission Order.

4 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc.'s Energy
5 Efficient Water Heater Rebate program, is hereby approved, as modified by Staff's recommendations
6 in this proceeding.

7 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc.'s
8 Commercial and Industrial Energy Efficiency Improvement Loan program is approved as a pilot-
9 program for a period of 16 months, and that following the 12th month of program operation, Sulphur
10 Springs Valley Electric Cooperative, Inc. make a filing detailing its experience with the program and
11 a recommendation regarding continuation of the program.

12 IT IS FURTHER ORDERED that the proposed Energy Efficient New Home or Remodel
13 Rebate program shall be denied, and Sulphur Springs Valley Electric Cooperative, Inc. shall
14 discontinue offering any incentive related to the replacement of any heating or cooling appliance
15 using an energy source other than electricity with an electric appliance in order to promote fuel
16 switching.

17 IT IS FURTHER ORDERED that the Industrial Energy Efficient Improvement Loan program
18 and Energy Efficient Improvement Loan Program shall be modified to be interest free.

19 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc.'s initial
20 DSM adjustor rate is \$0.00088 per kWh, until further Order of the Commission.

21 IT IS FURTHER ORDERED that the prudently incurred costs associated with approved DSM
22 programs, for the years 2008 and earlier, that have been factored into the WPFCA account balance
23 shall remain in the WPFCA account balance.

24 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall
25 recover the costs of its Renewable Energy Standard Tariff by means of an REST Adjustor
26 Mechanism and shall file with the Commission a REST tariff with conforming changes within 30
27 days of the effective date of this Decision.

28 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall

1 recover the costs of its purchased fuel and power used to provide service to its members in a
2 Wholesale Power and Fuel Cost Adjustor mechanism, such adjustor to operate as discussed herein
3 and in Staff's testimony, and which may only be increased upon Order of the Commission, but which
4 may be decreased by Sulphur Springs Valley Electric Cooperative, Inc. without Commission Order.

5 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. as a
6 matter of compliance, shall docket by October 30, 2009, a report setting forth the manner and dates
7 its shall conduct public forums in the communities served by the planned 69kV line and associated
8 upgrades. This report shall also discuss the topics to be addressed at the public forums and the topics
9 shall include, but not be limited to, addressing how renewable energy generation (in particular
10 distributed generation) could be incorporated into the generation plans to serve the area covered by
11 the planned 69kV line and associated upgrades.

12 IT IS FURTHER ORDERED that by July 30, 2010, Sulphur Springs Valley Electric
13 Cooperative, Inc., as a matter of compliance, shall docket a report discussing the outcome of the
14 public forums and also discussing how it plans to incorporate the reasonable and effective renewable
15 energy proposals resulting from the public forums.

16 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. as a
17 matter compliance, shall docket by December 31, 2009, a feasibility study prepared by an
18 independent third party that includes alternatives (including use of distributed renewable energy) that
19 could mitigate the need for construction of Sulphur Springs Valley Electric Cooperative, Inc.'s
20 proposed 69kV project. The feasibility study shall be available for discussion in public forums
21 conducted by the Sulphur Springs Valley Electric Cooperative, Inc. in the impacted communities. A
22 report and minutes from these public forums shall be docketed by Sulphur Springs Valley Electric
23 Cooperative, Inc. no later than July 30, 2010.

24 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall not
25 commence construction of the referenced 69kV line until the public has had an opportunity to review
26 and comment on the report and until further Order of the Commission.

27 IT IS FURTHER ORDERED that the Service Conditions, as set forth in Exhibit A-16 to this
28 proceeding are hereby approved.

1 IT IS FURTHER ORDERED that within a year of the effective date of this Decision, Sulphur
2 Springs Valley Electric Cooperative, Inc. shall file in this Docket, as a compliance item, its written
3 fuel procurement policies as recommended by Staff.

4 IT IS FURTHER ORDERED that within 30 days of the effective date of this Decision,
5 Sulphur Springs Valley Electric Cooperative, Inc. shall file for approval of a tariff describing its bill
6 estimation methodology.

7 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc. shall file
8 revised line extension policies within 60 days of the effective date of the Order, for Commission
9 approval which reflect a Schedule of Charges, a statement that quotes provided to customers will be
10 itemized and procedures for refunding amounts to customers when additional customers connect to
11 the line extension.

12 IT IS FURTHER ORDERED that Sulphur Springs Valley Electric Cooperative, Inc., shall file
13 in this docket one year from the effective date of this Decision, and annually thereafter, a report
14 detailing the total number of Residential TOU ratepayers and the cost savings or losses experienced
15 by the participants in the Residential TOU plan. If, after two years from the effective date of this
16 Decision, less than 10 percent of the eligible ratepayers are participating in Sulphur Springs Valley
17 Electric Cooperative Inc.'s Residential TOU plan, we will require Sulphur Springs Valley Electric
18 Cooperative, Inc. to file a plan for Commission approval, to increase participation in the Residential
19 TOU plan to at least 10 percent.

20 ...

21 ...

22 ...

23 ...

24 ...

25 ...

26 ...

27 ...

28 ...

IT IS FURTHER ORDERED that in its next rate case, Sulphur Springs Valley Electric Cooperative, Inc. shall file detailed and conventional unbundled rates that do not provide incentive or disincentive for customers who want to choose competitive generation.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN

COMMISSIONER

COMMISSIONER

COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 8th day of Sept., 2009.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT

DISSENT

1 SERVICE LIST FOR:

SULPHUR SPRINGS VALLEY ELECTRIC
COOPERATIVE, INC.

2
3 DOCKET NO.:

E-01575A-08-0328

4 Bradley S. Carroll
5 Jeffrey W. Crockett
6 SNELL & WILMER LLP
7 One Arizona Center
8 400 East Van Buren
9 Phoenix, Arizona 85004-2202
10 Attorneys for SSVEC

11 Janice Alward, Chief Counsel
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13 ARIZONA CORPORATION COMMISSION
14 1200 West Washington Street
15 Phoenix, Arizona 85007

16 Ernest Johnson, Director
17 Utilities Division
18 ARIZONA CORPORATION COMMISSION
19 1200 West Washington Street
20 Phoenix, Arizona 85007

1 **Q. Does Staff have any concerns about utilizing the WPCA mechanism to adjust for**
2 **power costs that differ from the base cost?**

3 A. Yes. Large changes to the WPCA mechanism make the cost of power less predictable for
4 customers, and may result in rate shocks. Staff recommendations for managing the
5 adjustor to limit unpredictability are discussed in the next section, on the Wholesale Power
6 Cost Adjustment mechanism.

7

8 **WHOLESALE POWER COST ADJUSTMENT ("WPCA") MECHANISM**

9 **Q. What is the WPCA mechanism?**

10 A. The WPCA mechanism is a purchased power adjustor that uses charges or credits to
11 compensate for the difference between the base cost of power and the actual cost of
12 wholesale power. A bank balance tracks a utility's over-collections and under-collections
13 for the cost of power and transmission. The SSVEC WPCA mechanism is adjusted
14 periodically to reduce large positive or large negative balances, returning over-collections
15 to ratepayers, or increasing the WPCA charge to pay down under-collections. Interest is
16 not applied to either over- or under-collected balances.

17

18 **Q. Does SSVEC have the authority to manage its bank balance by changing the WPCA**
19 **rate?**

20 A. Yes. SSVEC currently has the authority to change the WPCA rate without Commission
21 approval.

22

23 **Q. Please describe SSVEC's recent use of the WPCA mechanism.**

24 A. From January 2006 through September 2008 the SSVEC adjustor has ranged from minus
25 \$0.00100 per kWh (which returned an over-collected bank balance to ratepayers) to the

EXHIBIT

tabbies

S-12

current adjustor rate of \$0.04000, which adds four cents per kWh over the current base cost of \$0.05897. Please see the table below for additional details:

Table 2: Changes to the WPCA Rate 4/06-8/08

Date of change	Adjustment from/to	Bank Balance ¹
April 2006	(\$0.00100) to \$0.00881	\$403,637 under-collected
November 2006	\$0.00881 to \$0.01106	\$1,002,969 under-collected
February 2007	\$0.01106 to \$0.01606	\$1,919,641 under-collected
April 2007	\$0.01606 to \$0.01975	\$1,031,412 under-collected
January 2008	\$0.01975 to \$0.00805	\$1,585,042 over-collected
May 2008	\$0.00805 to \$0.01975	\$481,288 under-collected
August 2008	\$0.01975 to \$0.04000	\$4,305,485 under-collected

Q. Describe the impact of changes to the WPCA mechanism on the bank balance.

A. From December 2007 through July 2008 the unit cost of purchased power, per kWh, was higher than the cost per kWh being collected from customers, despite a May increase from \$0.00805 to \$0.01975 in the WPCA rate. For example, in July 2008, the unit cost of purchased power per kWh was \$0.09279, while the total rate being collected from customers was \$0.07872. (This amount includes the current base cost of power of \$0.05897 per kWh and \$0.01975 collected through the WPCA mechanism.) With collections from customers below actual costs, by July 2008 the under-collected bank balance had risen to \$4,305,485.48, as indicated above. (Compare this to the July 2007 bank balance of \$17,340.05; however, \$502,414.36, or 11.67%, of the \$4,305,485.48 balance in July 2008 arose from approved DSM charges added to the bank balance in July 2008).

When the WPCA surcharge was increased from \$0.01975 to \$0.4000 in August 2008, this increased the total rate collected from customers per kWh to \$0.09897, while the unit cost of purchased power per kWh was \$0.089761; with collections now exceeding the unit cost

¹ Balance cited in Table 2 in for the beginning of the month in which the WPCA rate was changed.

1 of purchased power, SSVEC began to reduce its large under-collection. As of October
2 2008 SSVEC's under-collected bank balance had decreased to \$1,055,935.96.

3
4 Exhibit 1, attached to this testimony, reflects the recent history of the bank balance and its
5 increasing volatility since January 2008.

6
7 **Q. What has been the impact of recent increases to the WPCA rate on SSVEC**
8 **customers?**

9 A. With an increase from \$0.00805 to \$0.01975 in April, and an increase from \$0.01975 to
10 \$0.04000 in August, SSVEC customers experienced a total \$0.03195 increase to their per
11 kWh cost between April and August 2008.

12
13 **Q. How would this impact an average residential customer's bill?**

14 A. Average usage in August was 873 kWh for Residential customers. (40,441 Residential
15 customers using a total of 35,319,400 kWh.) The total \$0.03195 increase would add
16 \$27.90 to an average August bill for Residential customers.

17
18 The \$0.01975 to \$0.0400 increase in August accounted for \$17.69 of the \$27.90. August
19 is a peak usage month, which magnifies the impact of a higher WPCA, but also reduces an
20 under-collected bank balance more rapidly.

21
22 **Q. Is Staff proposing any changes to the way in which SSVEC manages its WPCA**
23 **mechanism?**

24 A. Yes. Since January 2008, when SSVEC became a partial requirements member, the
25 Cooperative's energy costs have been more volatile. The greater volatility impacts the
26 bank balance and, consequently, the WPCA rate. In order to manage the WPCA rate,

1 Staff recommends that, in the future, SSVEC submit proposed increases to the WPCA rate
2 to the Commission for approval. Submitting proposed increases for approval would
3 ensure that impacts to the Cooperative's customers are regulated.
4

5 Staff does not recommend that SSVEC be required to seek approval for decreases to its
6 WPCA rate.
7

8 **Q. Is Staff proposing any other changes to the way in which SSVEC manages its WPCA**
9 **mechanism?**

10 A. Yes. Staff is recommending that set thresholds be established to trigger changes in the
11 WPCA mechanism rate for both over- and under-collected bank balances.
12

13 With respect to under-collected bank balances, SSVEC must file an application to increase
14 the WPCA rate either when the bank balance reaches the threshold for under-collected
15 balances for two consecutive months, or when it reasonably anticipates that the threshold
16 will be reached within six months and would continue at or above the threshold for two or
17 more consecutive months.
18

19 With respect to over-collections, SSVEC may return over-collected bank balances to its
20 customers at any time, except it must use the WPCA mechanism to return over-collections
21 once the threshold is reached and remains over the threshold for two consecutive months.

1 **Q. What are the benefits of SSVEC establishing set thresholds for its WPCA**
2 **mechanism?**

3 A. With respect to under-collections, a set threshold would limit the size of any negative bank
4 balance that could accumulate. This would have the effect of limiting increases to the
5 WPCA mechanism, thereby limiting rate shocks to the customers.

6
7 With respect to over-collections, a set threshold would ensure that positive bank balances
8 would be returned to customers in a timely and predictable fashion.

9
10 Another advantage to set thresholds is that a written, established policy concerning
11 thresholds makes the functioning of the WPCA mechanism more transparent and
12 predictable.

13
14 **Q. What thresholds is Staff proposing for the WPCA mechanism?**

15 A. Staff recommends a \$2 million threshold for under-collections and a \$1 million threshold
16 for over-collections.

17
18 **Q. How were these thresholds determined?**

19 A. The \$2 million limit on under-collections is designed to keep increases to the WPCA
20 mechanism low enough to limit rate shocks, while the \$1 million limit on over-collections
21 places a reasonable limit on how much SSVEC can owe each Residential customer before
22 it begins to refund an over-collection. Both thresholds are calculated based on how much
23 an individual Residential customer would owe, or be owed, for that single customer's
24 "share" of the bank balance. At \$2 million, a Residential customer's share of an under-
25 collected bank balance would be approximately \$40, while at \$1 million the average
26 SSVEC customer's share of an over-collection would be approximately \$20.

1 **Q. What public interest is served by requiring SSVEC to seek Commission approval for**
2 **increases to its adjustor, or for imposing thresholds on SSVEC's adjustor bank**
3 **balances?**

4 A. The Arizona Corporation Commission has the authority, and the obligation, to set fair,
5 just, and reasonable rates for Arizona utility ratepayers, whether the utility providing
6 service is investor-owned or a cooperative. This rate-setting includes regulating the ways
7 in which purchased power or fuel costs are passed on to customers, because the structure
8 of these pass-throughs have an impact on ratepayers. In this case, particularly given
9 SSVEC's recent transition to partial requirements status, it is in the public interest to
10 regulate the manner in which costs are passed through the WPCA mechanism, because
11 doing so protects SSVEC's members from rate shocks. It is also in the public interest to
12 establish thresholds; thresholds provide an additional limit on rate shocks, and ensure that
13 the bank balance is maintained at a reasonable level, even with SSVEC's greater exposure
14 to fluctuating market costs as a partial requirements member.

15

16 **Q. Is the Cooperative proposing any changes that would affect the WPCA?**

17 A. Yes. The Cooperative is proposing to include a pass-through of fuel costs that may arise if
18 SSVEC were to have its own generating units.

19

20 **Q. Does the inclusion of FERC Account 555 in the WCPA mechanism presume the**
21 **prudence of those fuel costs?**

22 A. No. To the extent that SSVEC were to own and operate its own generation, the fuel costs
23 would likely be includable for pass-through; however, in no way should that be construed
24 as a determination of prudence regarding those fuel costs.

1 **Q. Why is the Cooperative proposing this change to the WPCA?**

2 A. Prior to January 2008 AEPCO supplied SSVEC with all its power under a full
3 requirements contract. In January 2008 SSVEC became a partial requirements member of
4 AEPCO, meaning that some portion of SSVEC's future power supply may come from
5 owned generation sources, which require fuel, or through purchased power agreements,
6 where additional transmission costs would be incurred. The Cooperative has proposed
7 that the WPCA mechanism be revised to allow these costs to be recovered.

8
9 **Q. Does Staff agree with this proposed change?**

10 A. Yes. It is logical for the costs associated with both acquiring and generating power to be
11 recovered through the same adjustor mechanism. One benefit is that it clarifies the overall
12 cost of power. Another benefit is that the adjustor mechanism can be modified to limit
13 rate shocks to customers arising from the volatility of power costs. (Through, for
14 example, the use of bank balance thresholds. See Staff's additional testimony on this
15 subject, above.)

16
17 **Q. What cost components does SSVEC propose to include in its WPCA?**

18 A. The FERC Accounts SSVEC proposes to include in its WPCA mechanism consist of the
19 following:

- 20 • Steam Power Generation – Operation, FERC Accounts 500-507;
- 21 • Steam Power Generation – Maintenance, FERC Accounts 510-514;
- 22 • Nuclear Power Generation -- Operation, FERC Accounts 517-525;
- 23 • Nuclear Power Generation -- Maintenance, FERC Accounts 528-532;
- 24 • Hydraulic Power Generation -- Operations, FERC Accounts 535-540;
- 25 • Hydraulic power Generation -- Maintenance, FERC Accounts 541-545;
- 26 • Other Power Generation – Operation, FERC Accounts 546-550;

- Other Power Generation – Maintenance, FERC Accounts 551-554; and
- Purchased Power, FERC Accounts 555-557.

Q. Does Staff agree with the list of FERC accounts SSVEC proposes to include in its revised WPCA mechanism?

A. No. SSVEC's proposed list of FERC accounts is overbroad and includes costs that do not belong in a power and fuel adjustor, such as maintenance and rent costs.

Q. What cost components should be included in the WPCA mechanism?

A. The SSVEC power and fuel adjustor should include costs directly related to the purchase, generation or transmission of power. These include the following FERC Accounts: 501 (fuel costs for steam power generation, less legal fees, less fixed fuel costs except for gas reservation), 518 (fuel costs for nuclear power generation, less Independent Spent Fuel Storage Installation ("ISFI") regulatory amortization), 547 (fuel costs for other power generation), 555 (purchased power costs – demand and energy), and 565 (transmission of electricity by others, both firm and non-firm). Power supply costs directly assignable to special contract customers would not be included in the calculation.

Q. Why does Staff include wheeling costs from FERC Account 565?

A. With respect to FERC Account 565, both firm and non-firm wheeling costs are related to the transmission of power to SSVEC for resale. As such, these costs are appropriate for recovery through the power and fuel adjustor mechanism. In addition, if only non-firm wheeling costs were included in the adjustor, the manner of cost recovery (more immediate through an adjustor) could influence the type of contract negotiated, when the only consideration in selecting and negotiating contracts should be the best deal for ratepayers.

1 **Q. Should capital or legal costs go through the SSVEC WPCA mechanism?**

2 A. No, and SSVEC has stated that capital costs would not be recovered through the revised
3 adjustor mechanism. (Response to JKM 6.4) Legal costs are another example of costs
4 that should not go through the WPCA, as these are not appropriate for a power and fuel
5 adjustor.

6
7 **Q. Is Staff recommending any changes to the WPCA mechanism, if it is revised to**
8 **provide for recovery of owned-generation fuel and costs related to purchased power**
9 **contracts?**

10 A. Yes. Staff recommends that the name of the Wholesale Power Cost Adjustment
11 mechanism be changed to the "Wholesale Power and Fuel Cost Adjustment ("WPFCA")"
12 mechanism. The new name would be more descriptive of the types of costs recovered
13 through the revised adjustor.

14
15 **Q. Has the Cooperative proposed any other changes that would affect the WPCA?**

16 A. Yes. SSVEC's DSM costs are currently recovered through the Cooperative's WPCA
17 mechanism. SSVEC proposes to move recovery of its DSM costs out of the WPCA, and
18 to create a new DSM adjustment mechanism to recover a portion of its DSM costs.
19 (Please see Staff Witness Steve Irvine's testimony regarding SSVEC's proposal to roll a
20 portion of Test Year DSM costs into base rates.)

21
22 **Q. Is Staff opposed to moving DSM costs out of SSVEC's WPCA mechanism?**

23 A. No. Staff concurs that DSM funding should be moved out of the WPCA mechanism and
24 into a separate adjustor specifically designated to recover DSM costs. To include DSM
25 funding in the WPCA mechanism obscures both the cost of power and the cost of DSM.

1 Separate adjustors provide specific accountings for both elements, making the actual cost
2 of each as clear as possible for ratepayers.
3

4 **Q. Are there any Staff recommendations with respect to reporting on SSVEC's fuel**
5 **adjustor reports?**

6 A. Yes. Staff recommends that an SSVEC officer sign off on SSVEC's WPFCA reports.
7 This process is the same as Commission requirements for other entities in other rate cases.
8 An SSVEC officer should certify that all information provided in SSVEC's purchased
9 power and WPFCA reports is true and accurate to the best of his or her information and
10 belief.
11

12 **SERVICE CONDITIONS**

13 **Q. Has SSVEC revised its Service Conditions as part of the current rate case?**

14 A. Yes. SSVEC states that most of its changes were intended to clarify the Service
15 Conditions, make them consistent, ensure compliance with Commission rules and
16 incorporate changes in technology since the last rate case. The major proposed change
17 eliminates the construction allowance for line extensions for all classes.
18

19 **Q. Does Staff agree with elimination of the construction allowance for line extensions?**

20 A. Yes. SSVEC reports that costs associated with growth have "increased dramatically" in
21 recent years. Eliminating free footage would reduce SSVEC's costs associated with
22 growth, reduce the need for future rate increases and reduce the debt SSVEC incurs to
23 provide service.

MOHAVE ELECTRIC COOPERATIVE, INC.

CORRECTION

COMPARISON OF 2010 REVENUE UNDER EXISTING AND STAFF SURREBUTTAL RATES

	Cust	kWh		Adjusted 2010	Mohave Prop. Direct 2010	Change		Staff Surrebittal 2010	Change	
		Total	Avg Min			\$	%		\$	%
Residential	34,875	364,970,959	872	42,986,712	44,735,329	1,748,617	4.07%	44,715,676	1,728,964	4.02%
Irrigation Time of Use	12	1,730,345	12,016	166,306	168,026	1,720	1.03%	167,368	1,062	0.64%
Irrigation Pumping	11	2,572,007	19,485	302,194	309,962	7,768	2.57%	308,398	6,204	2.05%
Subtotal Irrigation	23	4,302,352	15,588	468,500	477,988	9,488	2.03%	475,766	7,266	1.55%
Small Comm Energy	3,201	42,164,591	1,098	4,900,351	5,177,391	277,040	5.65%	5,224,497	324,146	6.61%
Small Comm Demand	529	70,626,268	11,126	7,389,210	7,729,118	339,908	4.60%	7,720,820	331,610	4.49%
Small Comm TOU	8	1,020,044	10,625	96,177	100,936	4,759	4.95%	101,502	5,326	5.54%
Subtotal Small Comm	3,738	113,810,903	2,537	12,385,738	13,007,445	621,707	5.02%	13,046,819	661,081	5.34%
Large Comm & Industrial	118	170,994,538	4,495,062	15,775,430	16,108,634	333,204	2.11%	16,161,023	385,594	2.44%
LC&I TOU	3	564,880	15,691	48,035	67,443	19,408	40.40%	61,177	13,142	27.36%
Lighting Devices	* 1,151	1,100,103	80	98,025	103,184	5,159	5.26%	103,596	5,571	5.68%
Resale	* 1	46,862,961	3,905,247	3,698,667	3,698,667	0	0.00%	3,698,667	0	0.00%
Total Energy Sales	* 38,757	702,606,696	1,511	75,461,107	78,198,690	2,737,583	3.63%	78,262,725	2,801,617	3.71%
Other Revenue				606,899	863,547	256,647	42.29%	867,282	260,383	42.90%
Total Revenue				76,068,007	79,062,237	2,994,230	3.94%	79,130,007	3,062,000	4.0253%

* Total Customers excludes Lighting Devices and Resale

EXHIBIT
5-13

tabbles

MOHAVE ELECTRIC COOPERATIVE, INC.

CORRECTION

COMPARISON OF 2010 REVENUE UNDER EXISTING AND PROPOSED RATES (DETAIL)

	Cust	kWh		Adjusted 2010	Cents per kWh	Mohave Proposed 2010	Cents per kWh	Change under		Staff Proposed 2010	Cents per kWh	Change under	
		Total	Avg Mn					Mohave Proposed 2010	%			Staff Proposed 2010	%
Residential	34,775	364,111,753	873	\$ 42,878,813	11.8	\$ 44,621,441	12.3	\$ 1,742,628	4.06%	\$ 44,602,672	12.2	\$ 1,723,859	4.02%
Residential - Seasonal	1	549	46	\$ 164	29.9	\$ 235	42.8	\$ 71	43.29%	\$ 202	36.8	\$ 38	23.15%
Residential - Net Metering	72	640,060	741	\$ 81,352	12.7	\$ 86,113	13.5	\$ 4,761	5.85%	\$ 85,658	13.4	\$ 4,306	5.29%
Res - Gov	27	218,597	675	\$ 26,383	12.1	\$ 27,540	12.6	\$ 1,157	4.38%	\$ 27,145	12.4	\$ 761	2.88%
Residential	34,875	364,970,959	872	\$ 42,986,712	11.8	\$ 44,735,329	12.3	\$ 1,748,617	4.07%	\$ 44,715,676	12.3	\$ 1,728,984	4.02%
Irrigation Time of Use	12	1,730,345	12,016	\$ 166,306	9.6	\$ 168,026	9.7	\$ 1,720	1.03%	\$ 167,368	9.7	\$ 1,062	0.64%
Irrigation Pumping	11	2,572,007	19,485	\$ 302,194	11.7	\$ 309,962	12.1	\$ 7,768	2.57%	\$ 308,398	12.0	\$ 6,204	2.05%
Subtotal Irrigation	23	4,302,352	15,588	\$ 468,500	10.9	\$ 477,988	11.1	\$ 9,488	2.03%	\$ 475,766	11.1	\$ 7,266	1.55%
Small Commercial Energy	2,930	38,541,431	1,096	\$ 4,479,803	11.6	\$ 4,733,078	12.3	\$ 253,275	5.65%	\$ 4,776,317	12.4	\$ 296,514	6.62%
SC Energy Gov	267	3,559,150	1,111	\$ 413,221	11.6	\$ 436,237	12.3	\$ 23,016	5.57%	\$ 440,348	12.4	\$ 27,126	6.56%
SC Energy - Net Metering	4	64,010	1,334	\$ 7,327	11.4	\$ 8,076	12.6	\$ 749	10.22%	\$ 7,832	12.2	\$ 505	6.89%
Small Comm Energy	3,201	42,164,591	1,098	\$ 4,900,351	11.6	\$ 5,177,391	12.3	\$ 277,040	5.65%	\$ 5,224,497	12.4	\$ 324,146	6.61%
Small Commercial Demand	463	63,019,478	11,343	\$ 6,561,332	10.4	\$ 6,854,527	10.9	\$ 293,195	4.47%	\$ 6,846,574	10.9	\$ 285,242	4.35%
SC Demand Gov	65	7,582,510	9,721	\$ 825,265	10.9	\$ 871,832	11.5	\$ 46,567	5.64%	\$ 871,487	11.5	\$ 46,222	5.60%
SC Demand - Net Metering	1	24,280	2,613	\$ 2,613	10.8	\$ 2,759	11.4	\$ 146	5.58%	\$ 2,758	11.4	\$ 145	5.56%
Small Comm Demand	529	70,626,268	11,126	\$ 7,389,210	10.5	\$ 7,729,118	10.9	\$ 339,908	4.60%	\$ 7,720,820	10.9	\$ 331,610	4.49%
Small Comm TOU	8	1,020,044	10,625	\$ 96,177	9.4	\$ 100,936	9.9	\$ 4,759	4.95%	\$ 101,502	10.0	\$ 5,326	5.54%
Subtotal Small Comm	3,738	113,810,903	2,537	\$ 12,385,738	10.9	\$ 13,007,445	11.4	\$ 621,707	5.02%	\$ 13,046,819	11.5	\$ 661,081	5.34%
Large Power Sec	82	76,311,058	77,552	\$ 7,200,844	9.4	\$ 7,578,027	9.9	\$ 377,183	5.24%	\$ 7,606,509	10.0	\$ 405,665	5.63%
LP Gov	30	17,180,160	47,723	\$ 1,842,672	10.7	\$ 1,963,366	11.4	\$ 120,694	6.55%	\$ 1,976,562	11.5	\$ 133,890	7.27%
Large Power Primary	3	8,497,320	236,037	\$ 758,514	8.9	\$ 781,262	9.2	\$ 22,748	3.00%	\$ 783,115	9.2	\$ 24,601	3.2433%
LP Subtransmission	1	30,204,000	2,517,000	\$ 2,625,974	8.7	\$ 2,493,869	8.3	\$ (132,105)	-5.03%	\$ 2,501,089	8.3	\$ (124,885)	-4.76%
LP Substation	2	38,802,000	1,616,750	\$ 3,347,425	8.6	\$ 3,292,110	8.5	\$ (55,315)	-1.65%	\$ 3,293,749	8.5	\$ (53,677)	-1.60%
Large Comm & Industrial	118	170,994,538	4,495,062	\$ 15,775,430	9.2	\$ 16,108,634	9.4	\$ 333,204	2.11%	\$ 16,161,023	9.5	\$ 385,594	2.44%
LC&I TOU	3	564,880	15,691	\$ 48,035	8.5	\$ 67,443	11.9	\$ 19,408	40.40%	\$ 61,177	10.8	\$ 13,142	27.36%
Lighting Devices	1,151	1,100,103	80	\$ 98,025	8.9	\$ 103,184	9.4	\$ 5,159	5.26%	\$ 103,596	9.4	\$ 5,571	5.68%
Resale	1	46,862,961	3,905,247	\$ 3,698,667	7.9	\$ 3,698,667	7.9	\$ -	0.00%	\$ 3,698,667	7.9	\$ -	0.00%
Total Energy Sales	38,757	702,606,696	1,511	\$ 75,461,107	10.7	\$ 78,198,690	11.1	\$ 2,737,583	3.63%	\$ 78,262,725	11.1	\$ 2,801,617	3.71%
Other Revenue				\$ 606,899		\$ 863,547		\$ 256,647	42.29%	\$ 867,282		\$ 260,383	42.90%
Total Revenue				\$ 76,068,007		\$ 79,062,237		\$ 2,994,230	3.94%	\$ 79,130,007		\$ 3,062,000	4.0253%

* Total Customers excludes Lighting Devices and Resale

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (updated to 2010)

CORRECTION

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
472							
1. RESIDENTIAL SERVICE							
Residential							
Service Charge (12 Month Sum)	417,302	\$ -	\$ 13.50	\$ 13.50	\$ -	\$ 5,633,577	\$ 5,633,577
Energy Charge per kWh							
First 200 kWh per month	75,441,637	\$ 0.079958	\$ 0.013394	\$ 0.093352	\$ 6,032,162	\$ 1,010,465	\$ 7,042,628
Next 200 kWh per month	62,783,417	\$ 0.079958	\$ 0.013394	\$ 0.093352	\$ 5,020,036	\$ 840,921	\$ 5,860,958
Next 200 kWh per month	50,237,165	\$ 0.093458	\$ 0.014894	\$ 0.108352	\$ 4,695,065	\$ 748,232	\$ 5,443,297
Next 200 kWh per month	39,197,460	\$ 0.093458	\$ 0.014894	\$ 0.108352	\$ 3,663,316	\$ 583,807	\$ 4,247,123
Next 200 kWh per month	30,436,462	\$ 0.093458	\$ 0.014894	\$ 0.108352	\$ 2,844,531	\$ 453,321	\$ 3,297,852
Over 1,000 kWh per month	106,015,612	\$ 0.106958	\$ 0.016394	\$ 0.123352	\$ 11,339,218	\$ 1,738,020	\$ 13,077,238
Base Revenue	364,111,753				\$ 33,594,329	\$ 11,008,343	\$ 44,602,672
PPCA Revenue							
Total Revenue					\$ 33,594,329	\$ 11,008,343	\$ 44,602,672
Residential - Seasonal							
Service Charge (12 Month Sum)	11	\$ -	\$ 13.50	\$ 13.50	\$ -	\$ 149	\$ 149
Energy Charge per kWh							
First 200 kWh per month	201	\$ 0.079958	\$ 0.013394	\$ 0.093352	\$ 16	\$ 3	\$ 19
Next 200 kWh per month	200	\$ 0.079958	\$ 0.013394	\$ 0.093352	\$ 16	\$ 3	\$ 19
Next 200 kWh per month	148	\$ 0.093458	\$ 0.014894	\$ 0.108352	\$ 14	\$ 2	\$ 16
Next 200 kWh per month	0	\$ 0.093458	\$ 0.014894	\$ 0.108352	\$ -	\$ -	\$ -
Next 200 kWh per month	0	\$ 0.093458	\$ 0.014894	\$ 0.108352	\$ -	\$ -	\$ -
Over 1,000 kWh per month	0	\$ 0.106958	\$ 0.016394	\$ 0.123352	\$ -	\$ -	\$ -
Base Revenue	549				\$ 46	\$ 156	\$ 202
PPCA Revenue							
Total Revenue					\$ 46	\$ 156	\$ 202

Follows Structure of Mohave's Supplemental Schedule N-1.0

CORRECTION

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	472	Billing Units	Proposed Rate		Proposed Revenue	
			Pur Pwr	Dist Wires	Total	Total
1. RESIDENTIAL SERVICE (Continued)						
Residential - Net Metering						
Service Charge (12 Month Sum)		863		\$ 18.50	\$ 15,966	\$ 15,966
Energy Charge per kWh						
First 200 kWh per month		114,805	\$ 0.079958	\$ 0.013394	\$ 9,180	\$ 10,717
Next 200 kWh per month		97,201	\$ 0.079958	\$ 0.013394	\$ 7,772	\$ 9,074
Next 200 kWh per month		79,816	\$ 0.093458	\$ 0.014894	\$ 7,459	\$ 8,648
Next 200 kWh per month		63,706	\$ 0.093458	\$ 0.014894	\$ 5,954	\$ 6,903
Next 200 kWh per month		49,825	\$ 0.093458	\$ 0.014894	\$ 4,657	\$ 5,399
Over 1,000 kWh per month		234,706	\$ 0.106958	\$ 0.016394	\$ 25,104	\$ 28,952
Base Revenue		640,060			\$ 60,125	\$ 85,658
PPCA Revenue						
Total Revenue					\$ 60,125	\$ 85,658
Res - Gov						
Service Charge (12 Month Sum)		318		\$ 13.50	\$ 4,293	\$ 4,293
Energy Charge per kWh						
First 200 kWh per month		60,246	\$ 0.079958	\$ 0.013394	\$ 4,817	\$ 5,624
Next 200 kWh per month		44,692	\$ 0.079958	\$ 0.013394	\$ 3,573	\$ 4,172
Next 200 kWh per month		28,446	\$ 0.093458	\$ 0.014894	\$ 2,659	\$ 3,082
Next 200 kWh per month		20,173	\$ 0.093458	\$ 0.014894	\$ 1,885	\$ 2,186
Next 200 kWh per month		15,693	\$ 0.093458	\$ 0.014894	\$ 1,467	\$ 1,700
Over 1,000 kWh per month		49,347	\$ 0.106958	\$ 0.016394	\$ 5,278	\$ 6,087
Base Revenue		218,597			\$ 19,679	\$ 27,145
PPCA Revenue						
Total Revenue					\$ 19,679	\$ 27,145
Base Revenue		364,970,959			\$ 33,674,179	\$ 44,715,676
PPCA Revenue					\$ -	\$ -
Total Revenue					\$ 33,674,179	\$ 44,715,676

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (updated to 2010)

CORRECTION

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
472							
2. IRRIGATION SERVICE							
<u>Irrigation Time of Use</u>							
Service Charge (12 Month Sum)	144	\$ -	\$ 66.91	\$ 66.91	\$ -	\$ 9,635	\$ 9,635
On-Peak Demand	2,234.49	\$ 8.63	\$ -	\$ 8.63	\$ 19,284	\$ -	\$ 19,284
NCP Demand	8,466.81	\$ -	\$ 1.68	\$ 1.68	\$ -	\$ 14,224	\$ 14,224
Energy Charge per kWh	1,730,345	\$ 0.071776	\$ 0.000016	\$ 0.071792	\$ 124,197	\$ 28	\$ 124,225
Base Revenue					\$ 143,481	\$ 23,887	\$ 167,368
PPCA Revenue					\$ 143,481	\$ -	\$ -
Total Revenue					\$ 143,481	\$ 23,887	\$ 167,368
<u>Irrigation Pumping</u>							
Service Charge (12 Month Sum)	132	\$ -	\$ 61.76	\$ 61.76	\$ -	\$ 8,152	\$ 8,152
NCP Demand	12,025.74	\$ 5.74	\$ 1.68	\$ 7.42	\$ 69,028	\$ 20,203	\$ 89,231
Energy Charge per kWh	2,572,007	\$ 0.072027	\$ 0.010016	\$ 0.082043	\$ 185,254	\$ 25,761	\$ 211,015
Base Revenue					\$ 254,282	\$ 54,117	\$ 308,398
PPCA Revenue					\$ 254,282	\$ -	\$ -
Total Revenue					\$ 254,282	\$ 54,117	\$ 308,398
Base Revenue					\$ 397,763	\$ 78,004	\$ 475,766
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 397,763	\$ 78,004	\$ 475,766
3. SMALL COMMERCIAL SERVICE							
<u>Sm Comm Demand - Net Metering</u>							
Service Charge (12 Month Sum)	5	\$ -	\$ 36.03	\$ 36.03	\$ -	\$ 180	\$ 180
NCP Demand > 3 kW	73.68	\$ 6.13	\$ 4.69	\$ 10.82	\$ 452	\$ 346	\$ 797
Energy Charge per kWh	24,280	\$ 0.072753	\$ 0.000598	\$ 0.073351	\$ 1,766	\$ 15	\$ 1,781
Base Revenue					\$ 2,218	\$ 540	\$ 2,758
PPCA Revenue					\$ 2,218	\$ -	\$ -
Total Revenue					\$ 2,218	\$ 540	\$ 2,758

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (updated to 2010)

MOHAVE ELECTRIC COOPERATIVE, INC. CORRECTION

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

472	Billing Units	Proposed Rate		Proposed Revenue					
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total		
3.	SMALL COMMERCIAL SERVICE (Continued)								
	Small Commercial Demand								
	Service Charge (12 Month Sum)	5,552	\$ -	\$ 36.03	\$ 36.03	\$	-	\$ 200,039	\$ 200,039
	NCP Demand > 3 kW	187,060.45	\$ 6.13	\$ 4.69	\$ 10.82	\$	1,146,681	\$ 877,314	\$ 2,023,994
	Energy Charge per kWh	63,019,478	\$ 0.072753	\$ 0.000598	\$ 0.073351	\$	4,584,856	\$ 37,686	\$ 4,622,542
	Base Revenue					\$	5,731,537	\$ 1,115,038	\$ 6,846,574
	PPCA Revenue					\$	-	\$ -	\$ -
	Total Revenue					\$	5,731,537	\$ 1,115,038	\$ 6,846,574
	Small Commercial Energy								
	Service Charge (12 Month Sum)	35,164	\$ -	\$ 18.50	\$ 18.50	\$	-	\$ 650,534	\$ 650,534
	Energy Charge per kWh	38,541,431	\$ 0.087338	\$ 0.019710	\$ 0.107048	\$	3,366,132	\$ 759,652	\$ 4,125,783
	Base Revenue					\$	3,366,132	\$ 1,410,186	\$ 4,776,317
	PPCA Revenue					\$	-	\$ -	\$ -
	Total Revenue					\$	3,366,132	\$ 1,410,186	\$ 4,776,317
	Small Commercial - Net Metering								
	Service Charge (12 Month Sum)	49	\$ -	\$ 20.00	\$ 20.00	\$	-	\$ 980	\$ 980
	Energy Charge per kWh	64,010	\$ 0.087338	\$ 0.019710	\$ 0.107048	\$	5,591	\$ 1,262	\$ 6,852
	Base Revenue					\$	5,591	\$ 2,242	\$ 7,832
	PPCA Revenue					\$	-	\$ -	\$ -
	Total Revenue					\$	5,591	\$ 2,242	\$ 7,832
	Small Commercial TOU								
	Service Charge (12 Month Sum)	91	\$ -	\$ 41.01	\$ 41.01	\$	-	\$ 3,732	\$ 3,732
	On-Peak Demand	1,430.12	\$ 14.45	\$ -	\$ 14.45	\$	20,665	\$ -	\$ 20,665
	NCP kW	3,175.62	\$ -	\$ 4.69	\$ 4.69	\$	-	\$ 14,894	\$ 14,894
	Energy Charge per kWh	1,020,044	\$ 0.045399	\$ 0.015590	\$ 0.060989	\$	46,309	\$ 15,902	\$ 62,211
	Base Revenue					\$	66,974	\$ 34,528	\$ 101,502
	PPCA Revenue					\$	-	\$ -	\$ -
	Total Revenue					\$	66,974	\$ 34,528	\$ 101,502
	SC Energy Gov								
	Service Charge (12 Month Sum)	3,208	\$ -	\$ 18.50	\$ 18.50	\$	-	\$ 59,348	\$ 59,348
	Energy Charge per kWh	3,559,150	\$ 0.087338	\$ 0.019710	\$ 0.107048	\$	310,849	\$ 70,151	\$ 381,000
	Base Revenue					\$	310,849	\$ 129,499	\$ 440,348
	PPCA Revenue					\$	-	\$ -	\$ -
	Total Revenue					\$	310,849	\$ 129,499	\$ 440,348

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (updated to 2010)

MOHAVE ELECTRIC COOPERATIVE, INC. CORRECTION

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

472	Billing Units	Proposed Rate		Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Total	
3.	SMALL COMMERCIAL SERVICE (Continued)					
	SC Demand Gov	784				
	Service Charge (12 Month Sum)					
	NCP Demand > 3 kW	26,495.68				
	Energy Charge per kWh	7,582,510				
	Base Revenue					
	PPCA Revenue					
	Total Revenue					
	Base Revenue					
	PPCA Revenue					
	Total Revenue					
4.	LARGE COMMERCIAL & INDUSTRIAL SERVICE					
	Large C&I Secondary	983				
	Service Charge (12 Month Sum)					
	NCP Demand	189,369.16				
	Energy Charge per kWh	76,311,058				
	Base Revenue					
	PPCA Revenue					
	Total Revenue					
	Large C&I Primary	36				
	Service Charge (12 Month Sum)					
	NCP Demand	17,172.00				
	Energy Charge per kWh	8,497,320				
	Primary Discount on Demand & Energy					
	Base Revenue					
	PPCA Revenue					
	Total Revenue					

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
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Test Year Ended December 31, 2009 (updated to 2010)

MOHAVE ELECTRIC COOPERATIVE, INC. CORRECTION

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

472	Billing Units	Proposed Rate			Proposed Revenue		
		Pur Pwr	Dist Wires	Total	Pur Pwr	Dist Wires	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)							
Large C&I TOU-F (Proposed to be available only to customers subscribing to Large C&I TOU as of 03/01/2012)							
Service Charge (12 Month Sum)	31	\$ -	\$ 189.00	\$ 189.00	\$ -	\$ 5,859	\$ 5,859
On-Peak Demand	690.80	\$ 11.11	\$ -	\$ 11.11	\$ 7,675	\$ -	\$ 7,675
NCP kW	5,713.20	\$ -	\$ 3.22	\$ 3.22	\$ -	\$ 18,397	\$ 18,397
Energy Charge per kWh	564,880	\$ 0.045405	\$ 0.006370	\$ 0.051775	\$ 25,648	\$ 3,598	\$ 29,247
Base Revenue					\$ 33,323	\$ 27,854	\$ 61,177
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 33,323	\$ 27,854	\$ 61,177
Large C&I TOU (Proposed to be available to all Large C&I customers)							
Service Charge (12 Month Sum) <i>new proposal; no test year subscription</i>		\$ -	\$ 189.00	\$ 189.00	N/A	N/A	N/A
On-Peak Demand <i>new proposal; no test year subscription</i>		\$ 23.00	\$ -	\$ 23.00	N/A	N/A	N/A
NCP kW <i>new proposal; no test year subscription</i>		\$ -	\$ 3.22	\$ 3.22	N/A	N/A	N/A
Energy Charge per kWh <i>new proposal; no test year subscription</i>		\$ 0.045405	\$ 0.006370	\$ 0.051775	N/A	N/A	N/A
Base Revenue					N/A	N/A	N/A
PPCA Revenue					N/A	N/A	N/A
Total Revenue					N/A	N/A	N/A
Large C&I GOV							
Service Charge (12 Month Sum)	362	\$ -	\$ 175.00	\$ 175.00	\$ -	\$ 63,350	\$ 63,350
NCP Demand	64,343.36	\$ 7.81	\$ 3.22	\$ 11.03	\$ 502,522	\$ 207,186	\$ 709,707
Energy Charge per kWh	17,180,160	\$ 0.063682	\$ 0.006370	\$ 0.070052	\$ 1,094,067	\$ 109,438	\$ 1,203,505
Base Revenue					\$ 1,596,589	\$ 379,973	\$ 1,976,562
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 1,596,589	\$ 379,973	\$ 1,976,562
Billed at Subtransmission Delivery Level							
LC&I Trans (Current TOU)							
Service Charge (12 Month Sum)	12	\$ -	\$ 175.00	\$ 175.00	\$ -	\$ 2,100	\$ 2,100
NCP kW	53,106.00	\$ 7.81	\$ 3.22	\$ 11.03	\$ 414,758	\$ 171,001	\$ 585,759
Energy Charge per kWh	30,204,000	\$ 0.063682	\$ 0.006370	\$ 0.070052	\$ 1,923,451	\$ 192,399	\$ 2,115,851
Subtransmission Discount on Demand & Energy		-7.50%	-7.50%	-7.50%	\$ (175,366)	\$ (27,255)	\$ (202,621)
Base Revenue					\$ 2,162,843	\$ 338,246	\$ 2,501,089
PPCA Revenue					\$ -	\$ -	\$ -
Total Revenue					\$ 2,162,843	\$ 338,246	\$ 2,501,089

Follows Structure of Mohave's Supplemental Schedule N-1.0

Mohave Electric Cooperative, Inc.
Docket No. E-01750A-11-0136
Test Year Ended December 31, 2009 (updated to 2010)

CORRECTION

MOHAVE ELECTRIC COOPERATIVE, INC.

DEVELOPMENT OF 2010 REVENUE UNDER STAFF SURREBUTTAL RATES

	472	Billing Units	Proposed Rate		Proposed Revenue	
			Pur Pwr	Dist Wires	Total	Total
4. LARGE COMMERCIAL & INDUSTRIAL SERVICE (Continued)						
LP Substation Billed at Substation Delivery Level						
Service Charge (12 Month Sum)		24				
NCP kW		67,500.00				
Energy Charge per kWh		38,802,000				
Substation Discount on Demand & Energy						
Base Revenue			\$ -	\$ 175.00	\$ 175.00	\$ 4,200
PPCA Revenue			\$ 7.81	\$ 3.22	\$ 11.03	\$ 217,350
Total Revenue			\$ 0.063682	\$ 0.006370	\$ 0.070052	\$ 2,470,989
			-5.00%	-5.00%	-5.00%	\$ (149,908)
						\$ (23,226)
						\$ 445,493
						\$ 3,293,749
			\$ 2,848,256	\$ 445,493	\$ 3,293,749	\$ -
			\$ 13,648,112	\$ 2,574,088	\$ 16,222,200	\$ -
		171,559,418	\$ -	\$ -	\$ -	\$ -
			\$ 13,648,112	\$ 2,574,088	\$ 16,222,200	\$ -
5. LIGHTING SERVICE						
175 W MVL	102 kWh per month	6,039	\$ 6.13	\$ 0.98	\$ 7.11	\$ 5,918
100 W HPS	51 kWh per month	2,594	\$ 3.07	\$ 5.39	\$ 8.46	\$ 13,982
175 W MVL CO	101 kWh per month	320	\$ 6.07	\$ 0.51	\$ 6.58	\$ 163
100 W HPS CO	51 kWh per month	3,644	\$ 3.07	\$ 2.34	\$ 5.41	\$ 8,527
250 W HPS	130 kWh per month	1,211	\$ 7.81	\$ 6.14	\$ 13.95	\$ 7,436
Base Revenue		13,808				\$ 36,026
PPCA Revenue						\$ -
Total Revenue						\$ 36,026
			\$ 37,019	\$ 5,918	\$ 42,937	\$ -
			\$ 7,964	\$ 13,982	\$ 21,945	\$ -
			\$ 1,942	\$ 163	\$ 2,106	\$ -
			\$ 11,187	\$ 8,527	\$ 19,714	\$ -
			\$ 9,458	\$ 7,436	\$ 16,893	\$ -
			\$ 67,570	\$ 36,026	\$ 103,596	\$ -
			\$ 67,570	\$ 36,026	\$ 103,596	\$ -
			\$ 3,222,980	\$ 475,687	\$ 3,698,667	\$ -
			\$ -	\$ -	\$ -	\$ -
			\$ 3,222,980	\$ 475,687	\$ 3,698,667	\$ -
6. RESALE REVENUE						
Base Revenue						\$ 3,698,667
PPCA Revenue						\$ -
Total Revenue						\$ 3,698,667
			\$ 3,222,980	\$ 475,687	\$ 3,698,667	\$ -
			\$ -	\$ -	\$ -	\$ -
			\$ 3,222,980	\$ 475,687	\$ 3,698,667	\$ -
7. TOTAL REVENUE						
Base Revenue						\$ 78,262,725
PPCA Revenue						\$ -
Other Revenue						\$ 867,282
Total						\$ 79,130,007
			\$ 61,208,344	\$ 17,054,381	\$ 78,262,725	\$ -
			\$ -	\$ -	\$ -	\$ -
			\$ 61,208,344	\$ 17,921,663	\$ 79,130,007	\$ -

Follows Structure of Mohave's Supplemental Schedule N-1.0